REVISION 7

NAVAL SHIPS' TECHNICAL MANUAL

CHAPTER 220 VOLUME 2

BOILER WATER/FEEDWATER TEST AND TREATMENT

THIS CHAPTER SUPERSEDES CHAPTER 220, VOLUME 2, SIXTH REVISION, DATED 1 JULY 1994

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15 DEC 1995

NAVSEA TECHNICAL MANUAL CERTIFICATION SHEET 1 OF 2

CERTIFICATION APPLIES TO: NEW MANUAL ☐ REVISION ☐ CHANGE ☐

APPLICABLE TMINS/PUB NO.: S9086-GX-STM-020/CH-220 V2 R7

PUBLICATION DATE (MO, DA, YR): 12/15/95

READING GRADE LEVEL (RGL): 8

TITLE: NAVAL SHIPS' TECHNICAL MANUAL
S9086-GX-STM-020 CHAPTER 220 V2
BOILER WATER/FEEDWATER TEST AND TREATMENT

TMCR/TMSR/SPECIFICATION NO.:

CHANGES AND REVISIONS:

PURPOSE: This revision to Chapter 220, Volume 2, reorganizes the manual to reflect the change for propulsion boilers from coordinated phosphate boiler water treatment to chelant treatment. Significant changes are identified as follows:

(continued on next page)

EQUIPMENT ALTERATION NUMBERS INCORPORATED:

TMDER/ACN NUMBERS INCORPORATED:

CONTINUE ON REVERSE SIDE OR ADD PAGES AS NEEDED

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PRINTING RELEASE					

NAVSEA 4160/8 (2-91)

2/25/91
0800/91

CERTIFICATION SHEET

TABLE OF CONTENTS

TABLE OF CONTENTS - Continued

TABLE OF CONTENTS - Continued

TABLE OF CONTENTS - Continued

TABLE OF CONTENTS - Continued

TABLE OF CONTENTS - Continued

TABLE OF CONTENTS - Continued

Chapter/Paragraph Page

TABLE OF CONTENTS - Continued

Chapter/Paragraph Page

TABLE OF CONTENTS - Continued

TABLE OF CONTENTS - Continued

Chapter/Paragraph Page

TABLE OF CONTENTS - Continued

Chapter/Paragraph Page

TABLE OF CONTENTS - Continued

TABLE OF CONTENTS - Continued

TABLE OF CONTENTS - Continued

TABLE OF CONTENTS - Continued

TABLE OF CONTENTS - Continued

TABLE OF CONTENTS - Continued

TABLE OF CONTENTS - Continued

TABLE OF CONTENTS - Continued

TABLE OF CONTENTS - Continued

TABLE OF CONTENTS - Continued

Chapter/Paragraph Page

TABLE OF CONTENTS - Continued

Chapter/Paragraph Page

TABLE OF CONTENTS - Continued

TABLE OF CONTENTS - Continued

TABLE OF CONTENTS - Continued

Chapter/Paragraph Page

TABLE OF CONTENTS - Continued

TABLE OF CONTENTS - Continued

TABLE OF CONTENTS - Continued

Chapter/Paragraph Page

TABLE OF CONTENTS - Continued

LIST OF TABLES

LIST OF TABLES - Continued

LIST OF TABLES - Continued

LIST OF TABLES - Continued

LIST OF ILLUSTRATIONS

LIST OF ILLUSTRATIONS - Continued

LIST OF ILLUSTRATIONS - Continued

LIST OF ILLUSTRATIONS - Continued

CHAPTER 220

BOILER WATER AND FEEDWATER
VOLUME 2 - BOILER WATER/FEEDWATER TEST AND TREATMENT

SECTION 20.

INTRODUCTION

220-20.1 PURPOSE

220-20.2

Shipboard water chemistry control requirements for propulsion, and auxiliary and waste heat steam generating systems are described in this volume. The theories of water treatment upon which the controls are based are included also. In many instances, information is given to provide engineering guidance to operating forces and industrial activities should a situation be encountered that is not specifically addressed by the chemistry control requirements.

220-20.3

Wherever guidance data and information to aid personnel in making sound engineering judgments is included (as differentiated from mandatory requirements amplifying Navy instructions), it is identified as such to eliminate confusion.

220-20.4

Mandatory requirements specified in this volume shall be met. Request for deviation from the specific requirements shall be made in writing to the Type Commander with an information copy to the immediate superior in the chain of command (ISIC), the Carderock Division Naval Surface Warfare Center (NSWCCD-SSES), and the Naval Sea Systems Command (NAVSEA). In extreme situations, deviations are authorized by the Commanding Officer and shall be reported. The requirements of this chapter apply during industrial availabilities. The Commander, Naval Shipyard, or Supervisor of Shipbuilding, Conversion, and Repair shall submit requests for deviation from the specific requirements to NSWCCD-SSES with information copies to the cognizant Type Commander, ISIC, the ship, and NAVSEA. The Type Commander, ISIC, and NSWCCD-SSES should be advised and assistance should be requested whenever unusual conditions arise which are not covered in this volume.

220-20.5 SCOPE

220-20.6

This volume contains instructions and guidance for maintenance of proper water chemistry in non-nuclear steam generating systems. The steam generating systems included herein are of three types:

1. Propulsion boilers.
2. Auxiliary boilers.
3. Waste heat boilers.

220-20.7 BACKGROUND

220-20.8

The control of steam plant water chemistry is necessary for the reliability of the entire main propulsion system. This control involves performing the following actions:

1. Production of good quality distillate from the distilling plant.
2. Detection and elimination of contaminants from reserve feedwater, condensate, and feedwater.
3. Maintenance of boiler water within prescribed limits by the addition of chemicals and by surface blowdown.
4. Removal of sludge by bottom blowdown.

220-20.9

Improper water conditions, resulting in boiler failures, are characterized by waterside deposits, corrosion, and carryover. Waterside deposits restrict heat transfer through the boiler tube metal which in turn leads eventually to tube failure. Sludge buildup from inadequate blowdowns and scaling from boiler water chemical undertreatment result in waterside deposits. Corrosion and general boiler waterside metal thinning are caused in several ways:

1. Chemical undertreatment.
2. Chemical overtreatment.
3. Waterside deposits.
4. Oxygen in boiler water.

220-20.10

Superheater steamside failure can occur from boiler water carryover with the saturated steam. Carryover leads to steamside deposits and improper heat transfer or stress corrosion cracking of stainless steel.

220-20.11 FEEDBACK

220-20.12

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SECTION 21.

STEAM PLANT WATER CHEMISTRY PRINCIPLES

220-21.1 STEAM PLANT WATER CHEMISTRY

220-21.2

Effective steam plant water chemistry control requires an understanding of the shipboard water cycle, the importance of good quality feedwater, and the ultimate damages that feedwater contaminants cause to boiler watersides and steamsides. Equally important is the development of an appreciation for the principles that govern the boiler water and feedwater treatments designed to prevent scale, corrosion, and carryover. The information presented in Section 21 is background material intended to aid in understanding the requirements set forth in Section 22 through Section 30.

220-21.3 SHIPBOARD WATER CYCLE

220-21.4 SUMMARY.

The overall shipboard water cycle is a closed system in which feedwater is fed to the boiler, the water is heated to generate steam, the steam does work in turbines, and is then condensed and returned to the feedwater system. Water for the cycle is obtained from seawater, which is taken into a distiller and evaporated to produce distillate. The distillate is stored in reserve feedwater tanks until needed as makeup feed. When needed to replace system losses, it is pumped or vacuum dragged to the condensate system where it is mixed with the condensate. The condensate then is pumped to the deaerating feed tank (DFT) where dissolved oxygen and other gases are removed. This deaerated water, now called feedwater, is pumped to the boiler where heat is applied. The boiler water is converted to steam and then it is used to drive turbines, operate auxiliary equipment, and provide heat energy to different parts of the ship. When most of the heat energy has been removed, the steam is condensed in the condenser, where it is ready to be recycled once again.

220-21.5

Because the cycle is continuous and closed, the same water remains in the system except for non-recoverable losses such as boiler blowdowns, steam catapults, laundry presses, steam atomizing burners, and miscellaneous leaks. Makeup feedwater is required to compensate for these system losses.

220-21.6

Auxiliary and waste heat boiler systems have essentially the same boiler water-steam-condensate-feedwater cycle except that the extent of deaeration varies with the feedwater heating equipment installed.

220-21.7

Figure 220-21-1 shows the feedwater and boiler water systems in the shipboard water cycle.

220-21.8 TERMINOLOGY.

Although the shipboard water cycle is continuous, different terminology is used to describe the water at different points. These distinctions are necessary because water quality standards vary throughout the system. The following terms identify the water at various points.

220-21.9 Distillate.

Distillate is the evaporated water that is discharged from the ship's distilling plant. Water in the shipboard water cycle normally begins as distillate. This distillate is stored in the reserve feedwater tanks until needed as makeup feedwater.

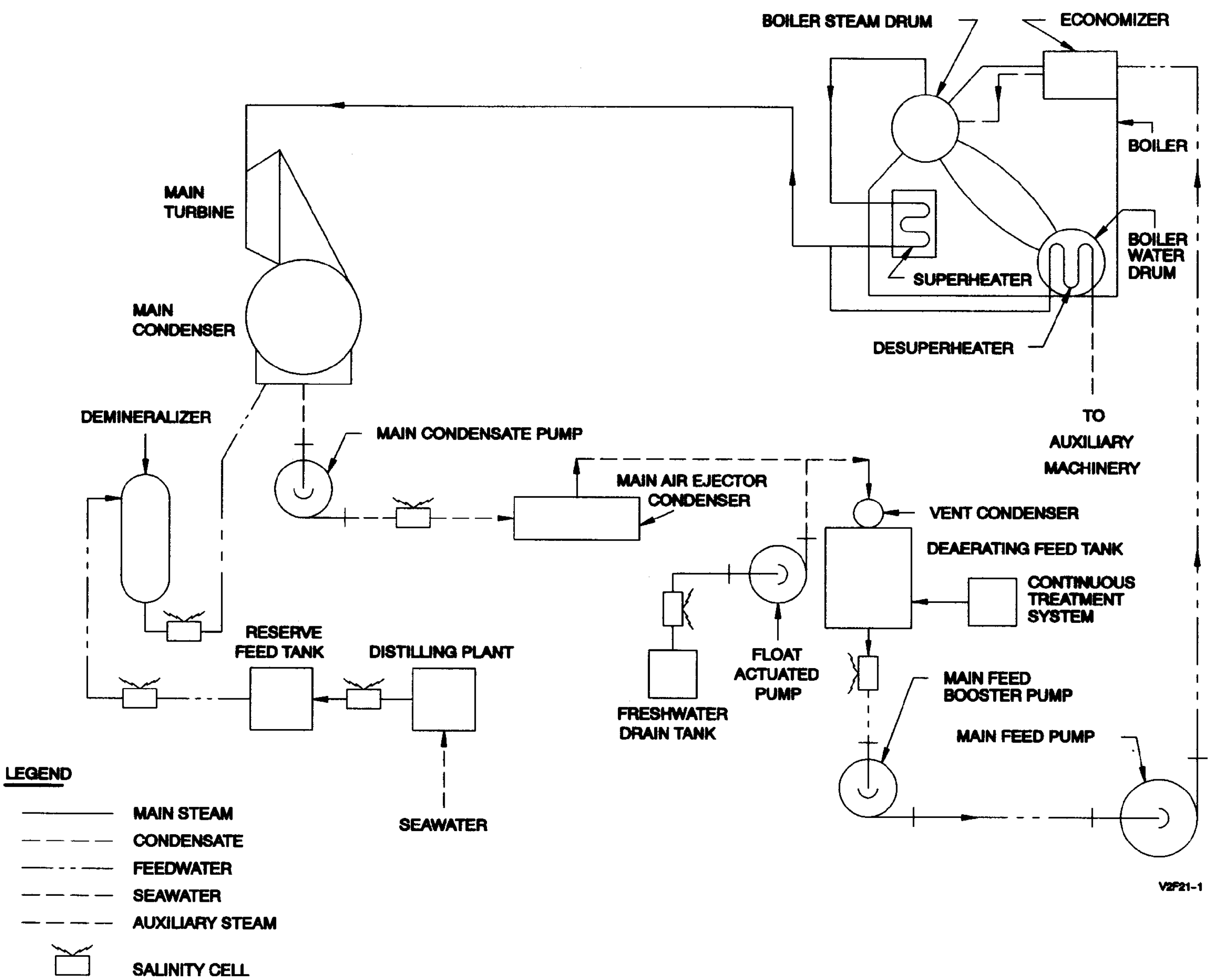


Figure 220-21-1. Shipboard Water Cycle.

220-21.10 Reserve Feedwater and Makeup Feedwater.

Distillate stored in the feedwater tanks is called reserve feedwater. The water flowing to the condensate system from the feed tanks is makeup feedwater. In ships equipped with demineralizers, the water flowing out of the demineralizer to the condensate system is termed demineralized makeup feedwater.

220-21.11 Condensate

After steam has done work, it is returned to the liquid state by cooling in a condenser. The condenser is a heat exchanger in which steam, under vacuum, flows over and is condensed on tubes through which seawater flows. The liquid condensed from steam is called condensate. Water from other sources (such as makeup feedwater and low pressure drains) is mixed with and becomes part of the condensate.

220-21.12

The principal sources of condensate are the main and auxiliary condensers. Other sources of condensate include the gland exhaust system, heating drains, distilling unit drains, steam coils, and other miscellaneous or service steam system drains. The condensate from various sources in the system is combined with makeup feedwater to maintain the proper quantity of water in the system. This composite is then sent to a DFT where dissolved oxygen and other gases are removed from the water. The discharge from the DFT is called deaerated feedwater. The DFT is designed to maintain the dissolved oxygen content of the deaerated feedwater at or below 15 ppb.

220-21.13 Feedwater (Deaerated Feedwater).

In the broad sense, the term feedwater refers to all of the various feed system waters. In the narrow sense, the term feedwater defines the water contained between the DFT and the boiler. Since deaerated feedwater is of special quality, the two feedwaters should not be confused.

220-21.14 Feedwater (Deaerated Feedwater) System.

In the broad sense, the term feedwater system includes the makeup feed and transfer systems, the main and auxiliary condensate systems, and the deaerated feedwater system. In the narrow sense, it includes only the deaerated feedwater system. As discussed in paragraph 220-21.13, the two usages of the term feedwater system should not be confused.

220-21.15 Boiler Water.

The deaerated feedwater, as it enters the boiler steam drum, is defined as boiler water. The term boiler water describes the water in the steam drum, water drum and headers, and generating tubes of the boiler.

220-21.16 Freshwater.

The term **freshwater** is generally used aboard ship to refer to potable water. However, certain steam drains returned to the condensate system are called freshwater drains. To avoid confusion, the term **freshwater** will not be used in this chapter except where the meaning is clear.

220-21.17 PROPULSION BOILER WATER FLOW.

Most naval boilers have an economizer through which the feedwater, under feed pump pressure, passes before entering the steam drum of the boiler. Figure 220-21-2 illustrates propulsion boiler water flow. The feedwater enters the steam drum through the feed inlet to the internal feed pipe. The water within boilers circulates by natural convection throughout the boiler circuits, that is, hot boiling water rises and cool or non-boiling water descends. The relatively cool or non-boiling water in the steam drum descends via the downcomers to the water drum and the headers. The water drum and the headers act to equalize the distribution of water to the generating tubes and provide a place for the accumulation of sludge, as discussed in paragraph 220-21.84. Boiler water circulates from the water drum and the headers to the boiler tubes, where saturated steam is formed. The steam/water mixture in the tubes rises to the steam drum. This mixture enters the steam drum beneath the manifold baffle plates (also known as girth plates or apron plates) where it is directed to steam separators and scrubbers. The liquid is separated from the steam by centrifugal action, returns to the central portion of the steam drum where it mixes with entering feedwater, and circulates again through the boiler circuits. The dried steam leaves the boiler via the dry pipe and steam drum outlet. This steam then passes through the superheater where it is heated to several hundred degrees Fahrenheit above saturation temperature. Most of this superheated steam goes to the main steam system and operates the main engine and principle auxiliary machinery. Some of the superheated steam flows through the desuperheater, which is a tube bank submerged beneath the water in either the steam drum or the water drum, and becomes desuperheated steam which is used to operate certain auxiliary equipment.

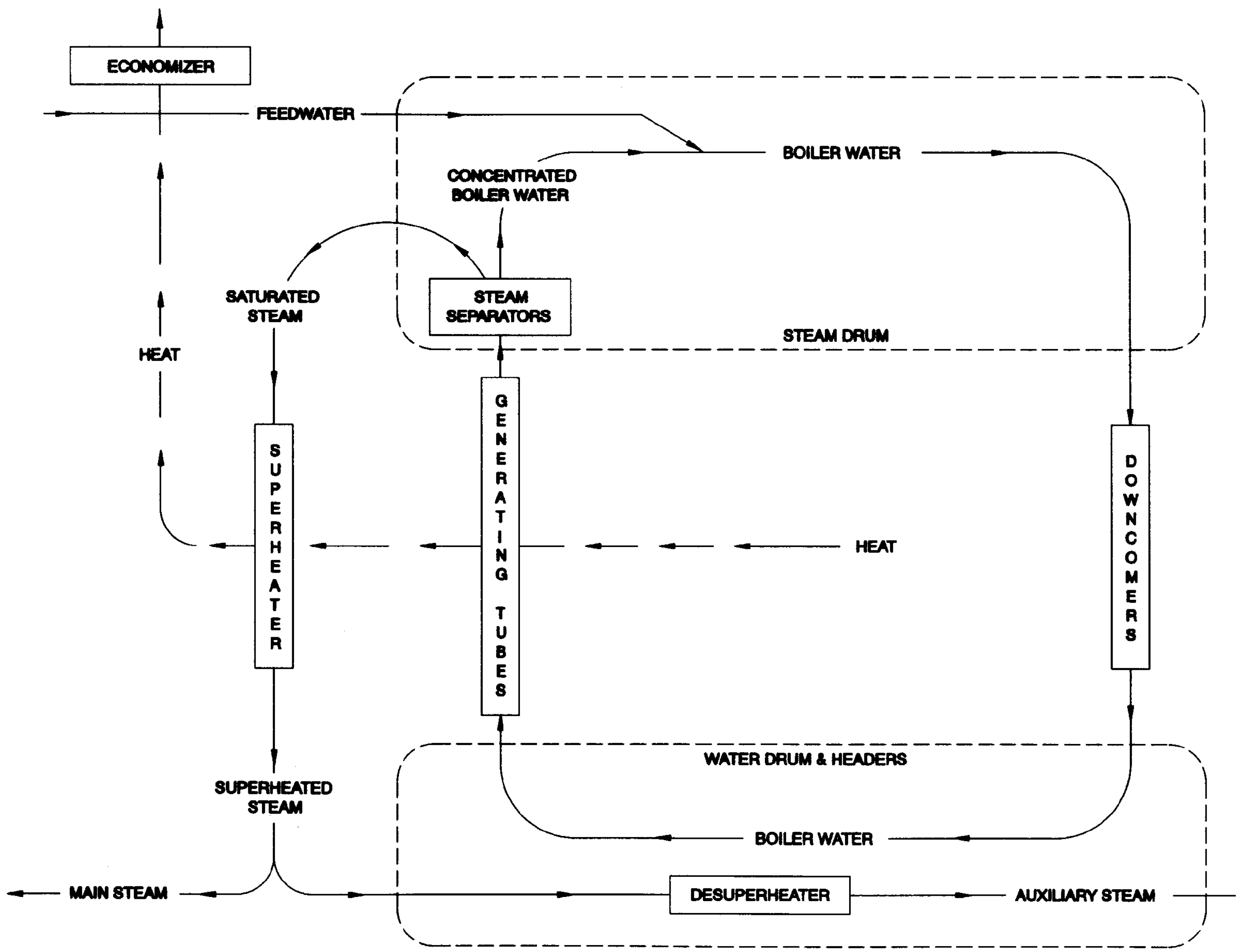


Figure 220-21-2. Propulsion Boiler Water Flow.

220-21.18 STEAM DRAINAGE SYSTEMS.

Service steam (low-pressure) drains and freshwater drains are not strictly part of the feedwater systems; however, these drains, including the saltwater feed heater drains and air ejector condenser drains of the distilling plant, are important elements affecting condensate and feedwater quality.

220-21.19 Service Steam (Low-Pressure) Drains.

The service steam drain system collects drainage from steam piping systems and steam equipment outside the machinery spaces that operate at pressures under 150 psi. These include services such as water heaters, space heaters, laundry, and food services equipment. The service steam drains discharge into the freshwater drain collecting tanks. On aircraft carriers the service steam drains discharge into service steam drain collecting tanks. The contents of the tanks are discharged by float-operated pumps to the condensate discharge system or are vacuum dragged into the main and auxiliary condensers. These service steam drains are subject to shore water and other types of contamination from hotel services.

220-21.20 Freshwater Drains.

The freshwater drain system collects drainage from various piping systems and equipment operating in the machinery spaces at pressures under 150 psi. These include services such as turbine gland seal and exhaust piping, warmup drains from noncondensing turbines and air ejector condenser drains. The drainage is discharged into the freshwater drain collecting tanks and, like the service steam drains, is pumped or vacuum dragged into the condensate system. The system contains funnels which must be kept covered to prevent entrance of contaminants.

220-21.21 Saltwater Feed Heater Drains (First Effect Tube Nest Drains) and Evaporator Air Ejector Condenser Drains.

The saltwater feed heater drains and air ejector condenser drains of the distilling plant discharge to the main condensate system and the freshwater drain tank, respectively. These drains are subject to seawater contamination because of tube leakage or brine carryover in the evaporator.

220-21.22 WATER IN THE PLANT ENVIRONMENT

220-21.23 GENERAL.

The nature of any water depends upon its past history. The chemistry of water is influenced by the amount and type of dissolved solids, suspended solids, and dissolved gases that contaminate it. Water is known as the universal solvent whose solvent action is so great that it tends to dissolve everything that it touches including any container holding it. Additionally, water will dissolve gases such as ammonia, hydrogen sulfide, oxygen, and carbon dioxide from the atmosphere. Water is the working fluid that transmits the energy by which steam-propelled ships operate. Propulsion plant water chemistry control is vital to prevent damage to boilers and other plant components by corrosion, fouling of heat transfer surfaces, and carryover of water with steam.

220-21.24 DEVELOPMENT OF A MAGNETITE LAYER.

If only pure oxygen-free water enters a boiler, an initial corrosion reaction between water and iron takes place resulting in the formation of a microscopically thin layer of protective magnetic iron oxide (Fe_3O_4, magnetite) as shown below:

$$\underset{\text{(iron metal)}}{3Fe^{\circ}} + \underset{\text{(water)}}{4HOH} \rightarrow \underset{\text{(magnetite)}}{Fe_3O_4} + \underset{\text{(hydrogen)}}{4H_2\uparrow}$$

220-21.25

After completion of this initial reaction, the metal is passivated and further corrosion is minimal. Any chemical or mechanical damage to the magnetite layer allows corrosion to advance until the protective layer repairs itself or until the tube fails. The symbol ($\uparrow$) means that the product is a gas. In addition, the feedwater treatment chemicals EDTA and hydrazine actively promote the formation of magnetitie. This results in a more protective magnetite layer and reduced corrosion.

220-21.26 EFFECTS OF BOILING ON DISSOLVED SOLIDS.

When heat is applied to a boiler tube, a thermal gradient develops. The outside surface of the tube is hotter than the inside surface of the tube which is hotter than the bulk of the boiler water. If the water contains dissolved solids, a film of nonboiling liquid at the tube surface must develop a higher concentration of solids than is in the bulk of the boiler water. When boiling begins, steam bubbles form at the tube surface further concentrating the solids around the bubbles. As the steam bubbles are released to the adjacent bulk boiler water, the solids that were concentrated around them are left behind. Fresh boiler water redissolves the material and prevents concentration or dry out of chemicals.

220-21.27

Anything that interferes with the free flow of water to the tube surface prevents the less concentrated boiler water from washing the metal. Porous deposits, crevices, pits, and leakage sites interfere and create low-flow areas. In effect, miniature boilers develop within the boiler and two boiler waters exist: the bulk of the fluid whose constituents are controlled by test and treatment, and the concentrated water at the tube surface. In boiler water treatment, the bulk boiler water chemistry must be controlled so that corrosive conditions or fouling cannot result when the water is concentrated at the tube surface.

220-21.28 CONTAMINANT CONCENTRATION.

As a boiler is steamed, the chemical composition of the boiler water continuously changes because the level of contamination builds up. In most naval plants, the dissolved and suspended materials contained in the feedwater concentrate in the boiler water at the rate of 10-fold per hour if the boiler is producing steam at about 50 percent of its rated capacity. If the feedwater contains 0.01 epm of chloride, the boiler water chloride concentration will increase by 0.1 epm in 1 hour. The concentration of suspended solids in the boiler water will also increase in the same manner.

220-21.29 EFFECTS OF CONTAMINANTS.

Modern naval boilers cannot be operated safely and efficiently without careful attention to and control of feedwater and boiler water quality. With proper control of water chemistry, proper plant operation, and proper layup during idle periods, naval boilers should last the life of the ship with no need to renew boiler tubes. If water conditions are not controlled within allowable limits, the high steam generation rates and temperatures will lead to rapid deterioration of waterside surfaces, scale formation, and carryover. All of the above conditions lead to serious boiler casualties. Because boilers concentrate all feedwater contaminants as steam is generated, boiler water quality and reliable boiler operation depend directly upon control of feedwater quality.

220-21.30

Because of ship operations, propulsion systems use water from distinctly variable sources. These can be classified into seawater and shore water.

220-21.31

Although the composition of seawater varies depending on location, the water of the different seas and oceans varies in composition no more than 10 percent. Because seawater compositions are relatively constant, the American Society for Testing and Materials (ASTM) has defined a reference composition for seawater given in Table 220-21-1.

Table 220-21-1. SOURCE WATER QUALITY

Constituent (ppm)	City Waters				Seawater
	San Diego	Mayport	Philadelphia	Norfolk	
Sodium	122	19	33	16	10,560
Calcium	80	59	43	21	400
Magnesium	31	25	17	1	1,270
Bicarbonate	159	162	53	38	140
Sulfate	302	69	121	31	2,650
Chloride	102	40	45	21	18,980
Silica	8.6	14.5	7.6	3.2	0.04 to 8.6
Conductivity (µmho/cm)	1,085	520	494	250	53,000
pH	8.2	7.3	7.1	7.4	8.2

220-21.32

Both municipal water (tap, city, potable, fresh, dock) and water originating from rivers, lakes, or wells are classified as shore water. Shore waters vary in composition among themselves and differ greatly from seawater. Some shore water analyses are also included for illustration in Table 220-21-1.

220-21.33

The constituents listed in Table 220-21-1 are not all-inclusive but do contain major contaminants of interest. Some are of serious significance in avoiding feed and boiler system failures through corrosion, scale, and carry-over. If feed and boiler water controls are neglected, both minor and catastrophic casualties will occur because chemical reactions will proceed as described in the following paragraphs.

220-21.34 pH (Acidic and Caustic Corrosion).

The definition and mathematical treatment of molecule, ion, and pH are given in **NSTM Chapter 220 Volume 1, Boiler Water/Feedwater - Water Chemistry** . In the descriptive sense, pure water breaks apart (ionizes) slightly, giving:

$$\underset{\text{(water molecule)}}{H_20} = \underset{\text{(water molecule)}}{HOH} \rightleftharpoons \underset{\substack{\text{(hydrogen ion)}\\ \text{(acid)}}}{H^+} + \underset{\substack{\text{(hydroxyl ion)}\\ \text{(alkali)}}}{OH^-}$$

As shown, H_2 O is HOH which ionizes to yield equivalent amounts of hydrogen ions (H^+) and hydroxyl ions (OH^-) (see NOTE). The reversing arrows signify that the water is in equilibrium with both ions. In pure water there are far more water molecules than there are hydrogen ions and hydroxyl ions, hence the arrow points strongly toward HOH. The concentration of hydrogen ions versus hydroxyl ions is determined by measuring pH. The pH scale ranges from 0 to 14 with 7 signifying that the solution is neutral; that is, having equivalent amounts of hydrogen ions and hydroxyl ions. If the pH is below 7, the water has more hydrogen ions and is acidic. If the pH is above 7, the water has more hydroxyl ions and is alkaline.

NOTE

The hydrogen ion in water is more correctly called the hydronium ion, represented by H_3O^+. Customary usage of the hydrogen ion implies H_3O^+. The hydrogen ion is written H^+ because it is understood that the hydrogen ion is attached to water.

220-21.35

The pH value is logarithmic; that is, pH values change by 1 when concentrations change by a factor of 10. Suppose that a pH of 7 means that one hydrogen ion and one hydroxyl ion are in solution. If the concentration of hydrogen ions increases to 10, pH becomes 6. If hydrogen ions increase to 100, pH becomes 5. With 1,000 hydrogen ions, pH is 4. In other words, water at pH 4 is 100 times more acidic than at pH 6. In the same manner, water at pH 11 has 100 times more hydroxyl ions in it than at pH 9, and is 100 times more alkaline (caustic).

220-21.36

In order to make water acidic it is necessary to either increase hydrogen ions or decrease hydroxyl ions. When the magnesium ion enters high-temperature water it reacts with the hydroxyl ion in the water and the solution becomes acidic. The reaction is:

$$\underset{\text{(magnesium ion)}}{Mg^{2+}} + \underset{\text{(water)}}{2HOH} \xrightarrow[\text{heat}]{\Delta} \underset{\text{(magnesium hydroxide)}}{Mg(OH)_2\downarrow} + \underset{\text{(hydrogen ion)}}{2H^+}$$

The magnesium hydroxide precipitates as a scale and the hydrogen ions, now in excess, acidify the water. The symbol ($\downarrow$) means that the reaction product is a solid which comes out of solution. This effect occurs almost exclusively with seawater because of the large amounts of magnesium in seawater. Acidic boiler water causes the passive Fe_3O_4 film on boiler metal to dissolve, resulting in further attack on the metal according to:

$$\underset{\text{(iron metal)}}{Fe^\circ} + \underset{\text{(hydrogen ion)}}{2H^+} \rightarrow \underset{\text{(dissolved iron)}}{Fe^{2+}} + \underset{\text{(hydrogen)}}{H_2}$$

220-21.37

In addition, if porous deposits are present on metal surfaces, the acid can concentrate under deposits, as discussed in paragraph 220-21.27, to cause a brittle failure known as hydrogen damage. The very small hydrogen gas molecules released during the corrosion process react with carbon in the metal to form a large molecule, methane gas. Because the methane gas molecule is large and trapped, it permeates the metal, excessive pressure develops, and the tube is weakened and eventually fails.

220-21.38

The effect of boiler water pH on the relative corrosion rate of boiler metal is illustrated in Figure 220-21-3. Both high and low pH are detrimental to boiler tubing. In order to make water alkaline it is necessary to either increase hydroxyl ions or decrease hydrogen ions. A condition of excessively high pH in the boiler water usually has two sources. Excessive hydroxyl ions result directly from accidental overaddition of caustic soda (NaOH, sodium hydroxide), or from shore water contamination. Shore water contamination increases the hydroxyl ion concentration in the boiler water regardless of the pH of the raw shore water. Shore waters have relatively large amounts of bicarbonate in comparison to acid-forming magnesium of seawater. In the boiler, bicarbonate breaks down according to:

$$\underset{\text{(bicarbonate ion)}}{HCO_3^-} \xrightarrow[\text{heat}]{\Delta} \underset{\text{(carbon dioxide)}}{CO_2\uparrow} + \underset{\text{(hydroxyl ion)}}{OH^-}$$

The hydroxyl ion increases pH while the carbon dioxide, a gas, is carried off with the steam. Whether the source is caustic soda or shore water, excess hydroxyl ions in the boiler water can cause damage that is as severe as the damage resulting from acidic water. The corrosion is called caustic corrosion, though caustic soda is not the sole source of hydroxyl ions. The mechanism of caustic corrosion is discussed in paragraph 220-31.12.

220-21.39

Bicarbonate contamination also causes acid formation, not in boiler water, but in steam condensate. According to the previous equation, bicarbonate in boiler water, whether from seawater or shore water, forms not only hydroxyl ions but also carbon dioxide. The carbon dioxide carries with the steam, then dissolves and reacts with the steam condensate, forming the hydrogen and bicarbonate ions according to:

$$\underset{\text{(carbon dioxide)}}{CO_2} + \underset{\text{(water)}}{HOH} \rightarrow \underset{\text{(carbonic acid)}}{H_2CO_3} \rightarrow \underset{\text{(hydrogen ion)}}{H^+} + \underset{\text{(bicarbonate ion)}}{HCO_3^-}$$

The hydrogen ion acidifies the condensate. Both the hydrogen ion and bicarbonate ion enter the boiler water where the following occurs:

$$\underset{\text{(hydrogen ion)}}{H^+} + \underset{\text{(bicarbonate ion)}}{HCO_3^-} \xrightarrow[\text{heat}]{\Delta} \underset{\text{(hydrogen ion)}}{H^+} + \underset{\text{hydroxyl ion)}}{OH^-} + \underset{\text{(carbon dioxide)}}{CO_2} \rightarrow \underset{\text{(water)}}{HOH} + \underset{\text{(carbon dioxide)}}{CO_2}$$

The carbon dioxide simply recycles in the system to acidify the condensate again. This acidic condensate causes corrosion of the entire condensate and feed systems and is particularly harmful in the presence of any dissolved oxygen. Products of corrosion of the condensate and feed systems are then carried into the boiler where they contribute to sludge formation.

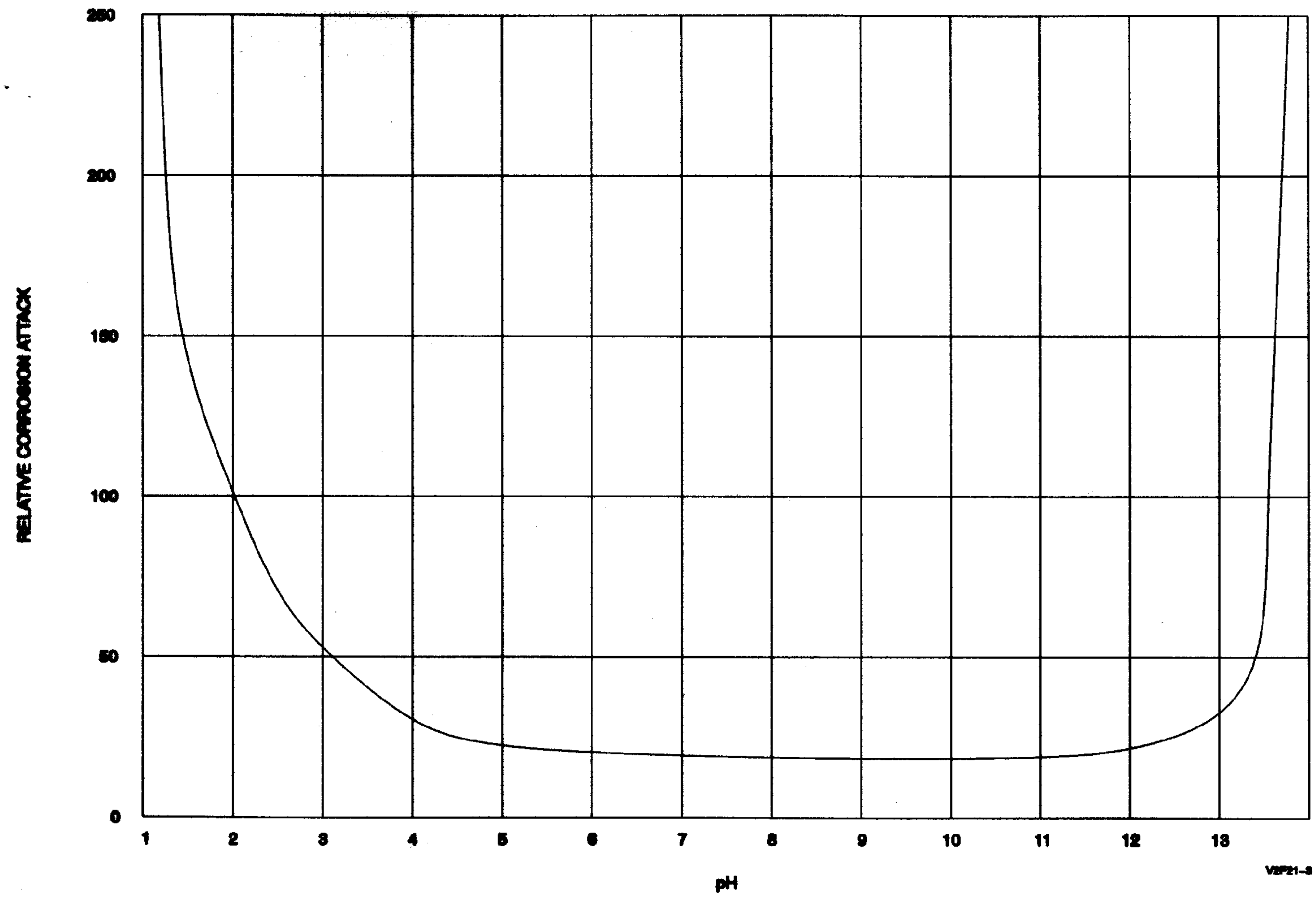


Figure 220-21-3. pH Effect on Boiler Metal Corrosion.

220-21.40 Hardness (Scale Formation).

Calcium and magnesium are the major hardness constituents and the primary sources of scale in boilers and feed system heat exchange equipment. The formation of magnesium hydroxide scale was previously described in paragraph 220-21.36. In the boiler water, calcium sulfate ($CaSO_4$) scale can also form because calcium sulfate, present in both seawater and shore waters, becomes less soluble as water temperature increases. It concentrates in the boiling film at the tube surfaces as discussed in paragraph 220-21.26. When the solubility limit is reached, solid calcium sulfate precipitates as scale on the tube surfaces. Scale found in feed systems is usually composed of calcium carbonate and calcium sulfate resulting from shore potable water leakage into steam drainage systems which in turn contaminates the boiler. Calcium carbonate is rarely found in high-pressure boilers because it decomposes at high temperatures.

220-21.41

All scale deposits act as insulators and reduce the heat transfer across the particular surface. Deposits will cause the temperature of the metal to increase until overheating, metal softening, blistering, and failure occur. Figure 220-21-4 illustrates such a situation in a boiler tube. In the illustration there is a 100°F drop across the tube from the fireside to the waterside surface. As the deposit restricts heat transfer, the surface of the tube under the deposit increases in temperature (to 800°F in this case). Eventually, as the deposit gets thicker, temperature will increase, the metal will soften, and the tube will blister (dotted line, 950°F). Because of very high furnace temperatures, modern naval boilers can tolerate no more than a few thousandths of an inch of scale on tube surfaces without suffering tube ruptures.

220-21.42 Dissolved Oxygen (Pitting Corrosion).

Water in contact with air will contain an amount of dissolved oxygen that is temperature and pressure dependent. Figure 220-21-5 illustrates the oxygen-dissolving capabilities of water. It can be seen from this graph that oxygen is more readily dissolved in water at lower temperatures. It also shows that oxygen solubility increases as the external pressure, the pressure in contact with the surface of the water, increases. When dissolved oxygen enters the boiler water, it causes localized corrosion and pitting of tube metal. The oxygen (O_2) dissolved in the boiler water will react with the iron (Fe) of the boiler waterside metal at selected surface points. At the anode, the iron will dissolve and form a substance known as ferrous hydroxide [$Fe(OH)_2$]. Some of this ferrous hydroxide is converted to hydrated ferric oxide ($Fe_2O_3 \cdot H_2O$). The mixture of ferrous hydroxide and hydrated ferric oxide is dehydrated and forms black iron oxide (Fe_3O_4, magnetite). This black iron oxide undergoes a change on its surface, a further reaction with oxygen (O_2), which results in a reddish iron oxide, Fe_2O_3.

220-21.43

As the oxygen attack continues over a period of time, the iron metal is dissolved and active oxygen scabs appear at each point. Active oxygen attack causes tubercles (scabs) to develop on the tube metal surface. A tubercle has a hard, reddish brown outer shell. The shell covers a pit in the boiler metal. There may be one isolated point of attack on the metal surface, or many points. Once an active oxygen scab forms, the corrosion of the metal continues, even though the condition causing dissolved oxygen contamination in the boiler water has been corrected. As the pH of the boiler water decreases, the severity of the dissolved oxygen attack increases. Boiler watersides which are open to the atmosphere are subject to oxygen corrosion if the surfaces are wet or if the humidity is high. Idle boilers under wet layup are also subject to oxygen corrosion unless protective measures are instituted.

220-21.44

The presence of oxygen in the steam/condensate/feedwater systems also causes general corrosion of iron, steel, copper, nickel, and various alloys in those systems whose corrosion products eventually reach the boiler. Corrosion is particularly severe when steam condensate is acidic. Corrosion products from the piping systems are carried into the boiler where they contribute to sludge formation.

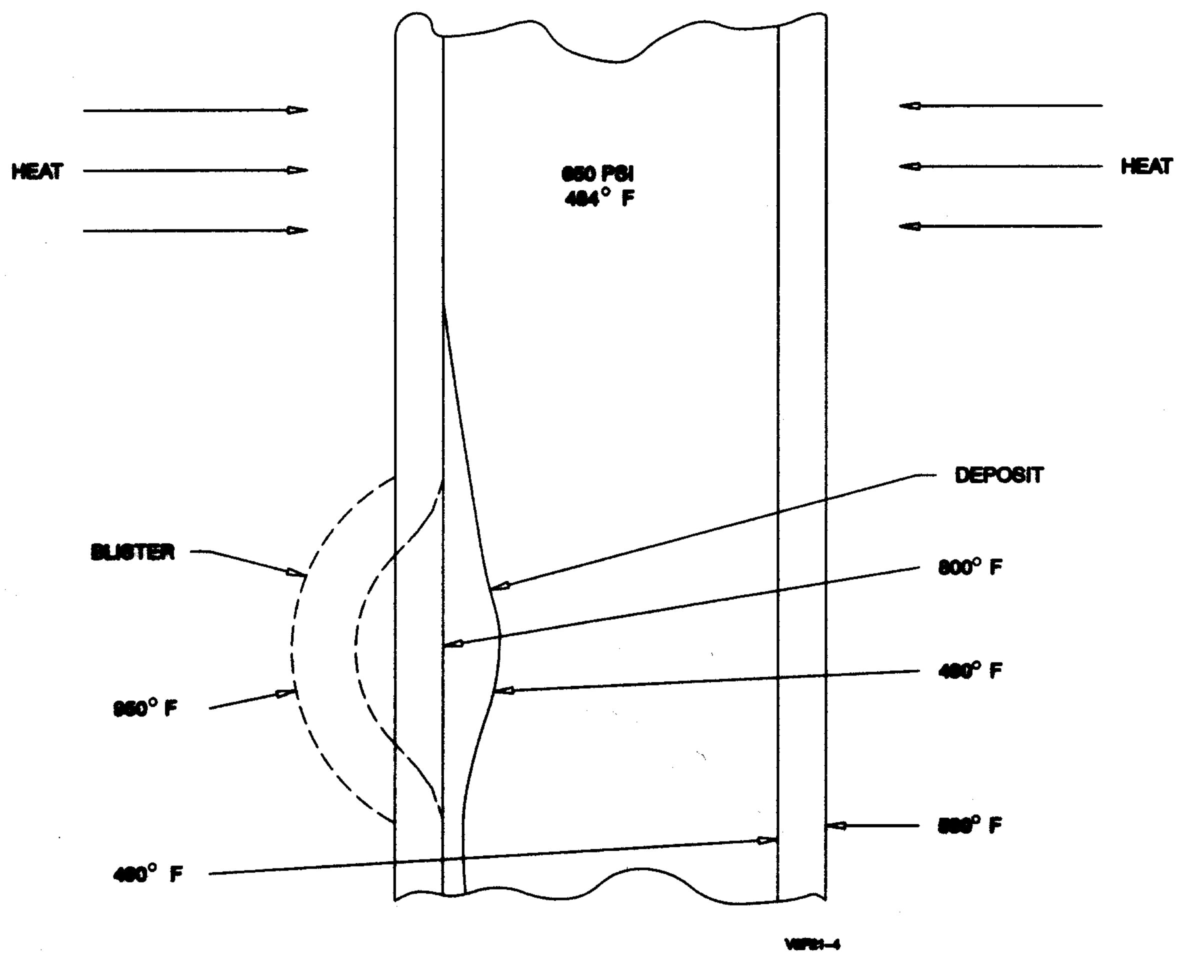


Figure 220-21-4. Effect of Boiler Deposit.

220-21.45 Chloride (Pitting Corrosion and Stress Corrosion Cracking).

Because of the large amount of chloride present in the major source of distillate and seawater, chloride is used primarily as an indicator of seawater contamination. Chloride is an **aggressive** ion which causes dissolution of the protective magnetite layer on boiler metal and inhibits its reformation. Pitting corrosion rather than general corrosion will occur. The sulfate ion, always present though not measured directly, tends to inhibit the destructive effects of small amounts of chloride on generating tube surfaces. Chloride can cause stress corrosion cracking of stainless steel components of propulsion systems.

220-21.46

Stainless steel, under stress, when subjected to chloride and oxygen, will suffer translational cracking of its crystals. When chloride concentrates in the boiler water from seawater contamination of the feedwater, it is possible for the chloride to carry over with the saturated steam into the superheater where it will deposit out on the superheater tube surfaces. If the superheater has stainless steel tubes, chloride stress corrosion can begin and may eventually lead to failure of the tubes. Chloride stress corrosion of stainless steel components of the desuperheated steam system can also occur. If a submerged desuperheater develops a leak, boiler water containing chloride will seep into the desuperheater resulting in contamination of many systems in the steam/water cycle.

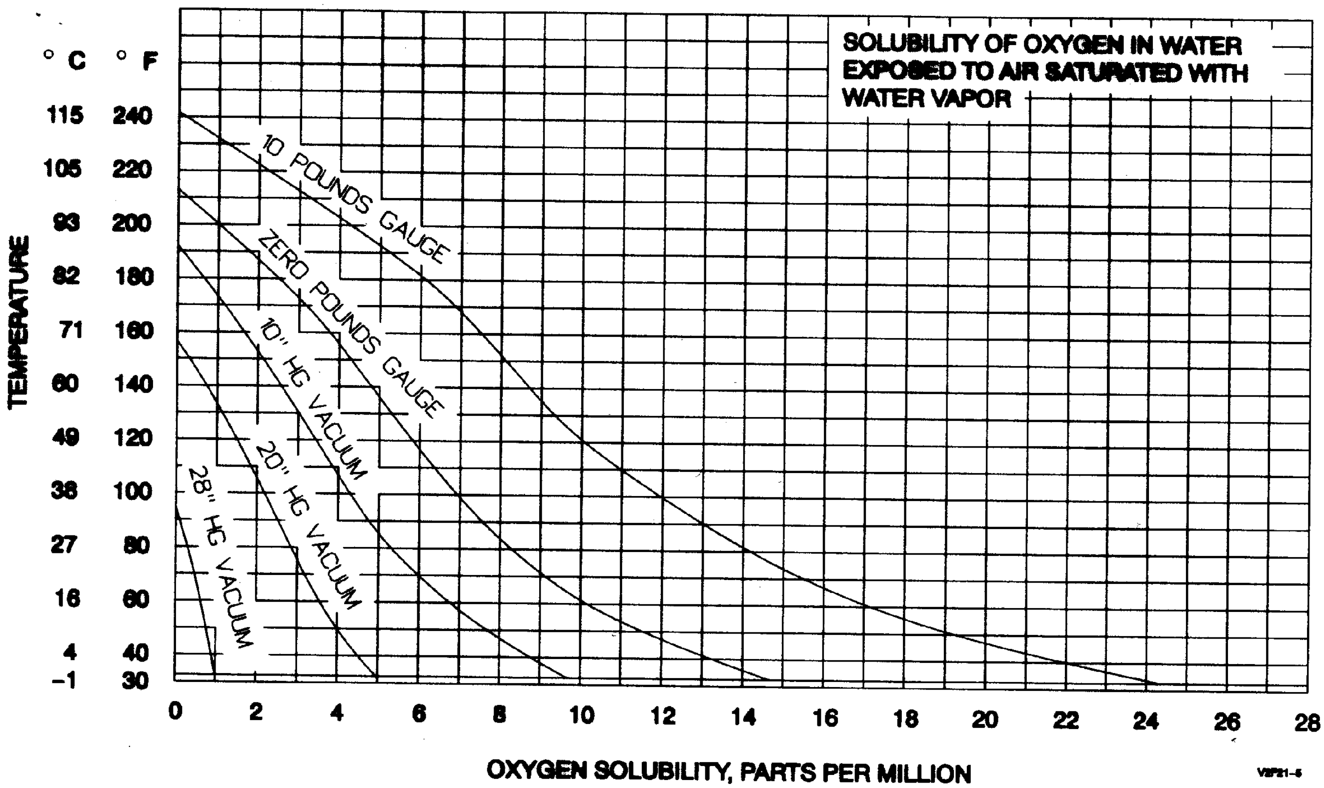


Figure 220-21-5. Oxygen-Dissolving Capabilities of Water.

220-21.47

Conductivity (General Corrosion and Carryover). The ability to conduct an electrical current is called conductivity and is expressed in micromhos per centimeter (µmho/cm). Conductivity and dissolved solids are interrelated since, in general, one is a measure of the other. In order for a solution to conduct a current, ions must be present. Virtually all materials dissolved in seawater, shore water, feedwater, and boiler water are ionic and do conduct a current. An exception is silica which is a monodic dissolved solid and does not conduct electricity. The feedwater treatment chemical, morpholine, contributes to conductivity but is a liquid, not a solid. (Refer to NSTM Chapter 220, Volume 1.)

220-21.48

Boiler metal corrosion results from electrolytic action. Electrolytic action depends on the presence of anodes and cathodes. (Refer to NSTM Chapter 220, Volume 1.) The chemical and physical variations in the boiler metal surface generate anodic and cathodic areas on the metal so that the surface of the metal has slight differences in electrical potential. In order for electrons to flow from the cathode to the anode, a conducting medium is needed. Pure water has a high resistance and low conductivity (about 0.1µmho/cm) so metal corrosion rate is low in pure water. As conductivity increases, the resistance to electron flow decreases and corrosion increases. Some ions in boiler water, notably the controlled hydroxyl and phosphate ions, suppress corrosion. Others, particularly the chloride and hydrogen (acid) ions, increase it. Most of the conductivity in feedwater results from the chloride, sulfate and bicarbonate compounds of sodium, calcium, and magnesium. Boiler water conductivity results from these contaminants and from treatment chemicals.

220-21.49

High conductivity water causes carryover. Boiling water produces bubbles that contain steam encircled by the water. The bubbles break to release the steam and the water falls back into the vessel holding the water. If the water is very pure, the steam bubbles break easily and an almost complete separation of water from steam is achieved. As the concentrations of dissolved and suspended solids or oil increase in water, the steam bubbles become stabilized and more difficult to break. The effectiveness of the separation of contaminated water from steam then deteriorates. Dissolved solids and suspended solids in boiler water increases in concentration with continued steaming. (They are controlled by blowdown.) The steam drum area above the surface of the boiler water fills up with these stabilized bubbles. Thus, some boiler water is carried along with the saturated steam into the dry pipe. This type of boiler water carryover is termed **foaming** . The boiler water entrained with the saturated steam evaporates in the superheater because the stabilized bubbles break at high superheat temperatures. Particles of material that were dissolved and suspended in the boiler water are carried by the velocity of the steam to different parts of the superheater. They deposit on the superheater surfaces, primarily in the first pass. Restriction of heat transfer, blistering, and eventual superheater failure can result whenever a deposit builds up. One of the materials dissolved in the boiler water, sodium chloride, can cause chloride stress corrosion cracking if deposited in stainless steel superheaters.

220-21.50

Another type of boiler water carryover is called **priming** . Priming is caused by high water level in the steam drum, extreme rolling and pitching of the ship, or mechanical failure of the steam separators or other steam drum internals. Priming consists of slugs of boiler water carried into the dry pipe. A slug of water may reach as far as the turbine with resultant damage to the unit.

220-21.51 Silica (Scale Formation)

Silica is not present in distillate derived from seawater in any appreciable amount because, in comparison to the rest of the dissolved materials, silica is a minor constituent of seawater. However, shore source feedwater, shore water, and condensed shore steam can contain silica. The silica is usually dissolved and is therefore considered a dissolved solid; however, it is not ionized and does not conduct an electric current. Since silica in the boiler water forms scale and can also volatilize with the steam depositing in steam lines and on turbine blades, it is a contaminant to be avoided. The silica scale formed on the generating surfaces is a mixture of calcium, magnesium and iron silicates. Silica scale behaves in the same manner as do other scales and all deposits illustrated in Figure 220-21-4. Use of unacceptable shore feedwater supplies must be avoided. Poor quality shore source feedwater, prepared by processing potable water through a pierside demineralizer, is by far the major cause of silica contamination. Suppliers of shore source feed are required to certify that the silica content of the water does not exceed 0.2 ppm. In addition, the ships with main propulsion boilers must sample and test the water using the silica test kit to ensure that the water meets this silica requirement. Other possible sources of silica contamination include desiccant used in dry layup and sandblast grit.

220-21.52

The desiccant used in dry layup is either silicic acid (silica gel) or an aluminum silicate (clay) which has been treated with sulfuric acid. Both desiccants are solids which are slightly soluble in distilled water and form acid solutions. In alkaline water, such as boiler water, both react with hydroxide ion to cause pH to decrease. Since silica gel is composed entirely of an acid, it will continue to react with hydroxide ion as it is added until the acid is neutralized and dissolved. The clay contains less acid so, initially, pH will decrease until sufficient hydroxide ion is added to neutralize the acid. The remaining clay will slowly dissolve in alkaline boiler water without further affecting pH meter readings or it will cake onto tube surfaces. One pound of either desiccant dissolved in 1,000 gallons of water contributes about 50 ppm of silica to the water. In order to avoid pH and silica control problems caused by desiccant, the desiccant is removed from the boiler after dry layup.

220-21.53 Suspended Solids (Sludge Formation and Carryover).

Seawater and shore waters contain variable amounts of suspended materials. In the case of seawater, most of the suspended solids are discharged overboard with the brine upon distillation of the water. Suspended solids are generally removed from shore source potable water by municipal pretreatment. Most suspended solids in the boiler result from corrosion and erosion of feed system metals when the water is not treated with morpholine. Suspended solids in boiler water contribute to the tendency of the water to carryover as discussed in paragraph 220-21.49, and contribute to sludge formation.

220-21.54

When a feed system contains large amounts of rust, as is experienced after overhaul or long-term dry layup, the rust can carry into boiler water upon system operation. The hydroxide ion in boiler water reacts with rust to form magnetite. The pH of boiler water decreases because of loss of hydroxide ion.

220-21.55 Fuel, Lubricating Oil and Preservatives (Deposits and Carryover).

Fuel oil and 2190 TEP lubricating oil accumulate in the steam drum to cause boiler water and oil to carryover with the steam. They also cause baked-on carbonaceous (carbon containing) deposits on the tubes and oily deposits (sludge balls) in the drums and headers. Detergent lube oils like 9250 will not rise into the steam drum but will emulsify throughout the boiler water and then will cause baked-on carbonaceous deposits, blistering and eventually tube failure. Preservatives behave in a manner similar to detergent lube oils. Conductivity equipment (which includes salinity indicators) and pH electrodes will not work when coated with oil.

220-21.56 Ion Exchange Resin (Acidic or Caustic Corrosion, Deposits).

The demineralizer contains both anion and cation exchange resins. Upon heating, the anion resin forms mildly alkaline (caustic) decomposition products. **The cation resin forms strongly acidic decomposition products** .

In addition, all calcium, magnesium, chloride, sulfate, and bicarbonate previously removed from the makeup water are released from the resin if it decomposes.

220-21.57 Dirt and Debris (Various).

Dirt, debris, and other foreign matter can cause any of the previously described problems depending on the chemical and physical characteristics of the dirt or debris. Water treatment may or may not be successful in compensating for some oddities caused by an unanticipated chemical reaction. It will not compensate for handhole plugs, flashlights, water jet lances, refractory brick, washers, wire brushes, welding rods, bags of desiccant, or other such items left in the boiler. Various forms of dirt and debris interfere with flow and heat transfer to cause overheat tube failures.

220-21.58 SOURCES OF FEEDWATER CONTAMINANTS.

The major contaminants that enter the feedwater system are seawater, shore water, metal corrosion products, suspended solids, and oxygen. Other contaminants include fuel and lubricating oil, preservatives, ion exchange resin, dirt, and debris.

220-21.59 Seawater.

Seawater containing the detrimental materials described in paragraphs 220-21.28 through 220-21.49 can enter the feedwater system from carryover in the distilling plant; from seawater leakage into the main and auxiliary condensers; and from bilge water leakage into the tanks, piping, and pumps when the bilges contain seawater. It can also result from malfunctioning or improper operation of units in the feedwater systems.

220-21.60

Seawater contamination of the feedwater requires increased chemical treatment of the boiler water. This increases the amount of dissolved and suspended solids in the boiler water. The boiler then requires more frequent blowdown. Excessive seawater contamination results in consumption of all the protective treatment chemicals in the boiler water, thereby causing corrosion, scale formation, and sludge formation to occur. Carryover results from the high concentrations of dissolved and suspended solids. If the problem continues unabated, generating and superheater tubes corrode, blister, and eventually rupture.

220-21.61 Shore Water.

Shore water may contaminate the feedwater system by leakage through malfunctioning swing check valves, galley mixing valves, laundry and scullery equipment and water heaters. Shore water contains high concentrations of dissolved solids, hardness, and silica. It can have either high or low pH but, in the boiler, shore water causes high pH. High concentrations of dissolved solids lead to boiler water carryover with the steam. Silica deposits on the boiler watersides and also in the steam system as it volatilizes along with the steam. Hardness leads to excessive usage of boiler water treatment chemicals and causes corrosion, scale, and sludge buildup. Excessively high pH will cause boiler metal corrosion. Shore water contamination, which can occur undetected during in-port cold iron periods, can result in contamination and deposit formation in a ship’s steam heating drain system. These deposits result in contamination of steam heating drains for several days or more after steaming is resumed.

220-21.62

Heat exchangers installed on Navy ships for service such as water heaters, dishwashing machines, and laundry equipment are required to be of a steam heating coil or electric heater type. Substitution with direct contact (mixing) type heaters will cause contamination of potable water with treatment chemicals and may also cause contamination of steam chains with shore water and laundry detergent. Direct contact heaters shall be replaced as soon as possible to avoid possible health hazards.

220-21.63 Metal Corrosion Products and Suspended Solids.

The metal surfaces of the feedwater system are sources for metal corrosion products in the feedwater. Water in the feed system has a pH of approximately 5 if not treated, which tends to cause corrosion of the metal surfaces. Some erosion, mechanical washing of particles from the metal surface, also occurs. The metal corrosion and erosion products contribute directly to sludge buildup in the boiler water.

220-21.64 Dissolved Oxygen.

Figure 220-21-5 illustrates the solubility of oxygen in water at various temperatures and pressures. Air, the source of dissolved oxygen, enters the feedwater system with the makeup feed and in various parts of the condensate system. By employing temperature and pressure control in the DFT, the concentration of dissolved oxygen in feedwater entering a boiler is minimized. Excessive dissolved oxygen in feedwater is caused by malfunctioning or improper operation of the DFT. When feedwater containing dissolved oxygen enters the boilers, it causes localized corrosion of the boiler metal. This is described as active oxygen attack and can become so severe that eventually the tube wall will be completely penetrated. Seawater contamination will accelerate dissolved oxygen attack.

220-21.65 Fuel Oil.

Distillate fuels, such as Diesel Fuel Marine (DFM), Navy Distillate (ND), and JP-5, are potential sources of contamination to the feedwater system because of their presence in the bilges. Fuel oil carries over with the steam, recycles in the system and eventually decomposes to form carbonaceous boiler or superheater deposits. It will also coat salinity cells, causing them to malfunction.

220-21.66 Lubricating Oil.

Lubricating oil (2190 TEP) is used extensively in steam plant machinery. Gland seals and oil seal rings are provided to keep lubricating oil from coming in contact with steam and condensate; however, the malfunction of these seals and rings will allow oil to contaminate the feedwater system. As in the case of fuel oil, lubricating oil leaks or spills accumulating in the bilges can also cause lube oil contamination of the feedwater. The drainage from lube oil heaters is another potential source of lube oil contamination in feedwater if a leak occurs in the lube oil heaters. Since a 2190 TEP type of lube oil tends to rise in water, it will accumulate in the steam drum and will carry over with the steam. The oil recycles in the system to eventually decompose, leaving carbonaceous boiler or superheater deposits. It will also coat the salinity cells making them malfunction. Detergent lube oils such as 9250 will not rise into the steam drum but will emulsify throughout the boiler water and then will bake onto tube surfaces causing blistering and, eventually, tube failure.

220-21.67 Preservatives.

Metal preservative coatings are used to protect the boiler piping and system equipment during construction. Contaminants of this type are generally found on new construction ships when the pre-boiler system is not properly flushed. Water contamination of this type can also result from the replacement of a system component without removing the preservative. If not removed, these organic materials will bake on the waterside surfaces of boiler tubes to cause blistering and, eventually, failure.

220-21.68 Ion Exchange Resin.

Resin beads can break if not properly handled, allowing fine particles of resin to pass through the retention screen. Screen damage also permits passage of intact resin into the makeup feed. Some ships have an orifice leveling leg installed on the demineralizer tank. Orifice strainers are required in this leg. The orifice strainers must have 100 mesh supported screen so that intact resin beads are retained. The most frequent cause of resin contamination has been installation of 30 mesh screens whose openings are larger than the beads. Other causes are collapsed or missing ion exchanger outlet strainers, backflow of resin into feed tanks through valve misalignment, and melting of resin by hot makeup feedwater (over 140°F). Hot makeup feed is the result of incorrect alignment of DFT fill and dump valves such that both valves are open at the same time. This incorrect alignment results in recirculating the hot deaerated feedwater to the reserve feed tank. Resin contamination cannot be detected in feedwater except visually. Anion resin decomposes at 60°C (140°F) and cation resin at 121°C (250°F), releasing alkaline and acidic products, respectively, or leaving powdery residues. Boiler water pH will decrease. Calcium, magnesium, chloride, sulfate, and bicarbonate are also released. Once resin contamination has occurred, flushing and hand removal or vacuuming of the condensate system and boiler is required for correction. In severe cases, water-jet cleaning of the boiler may be needed.

220-21.69 Dirt and Debris.

Poor housekeeping and lack of effective measures to exclude foreign materials lead to contamination with dirt and debris. If a boiler or piping system is open, dirt can enter. Openings should be covered when not actually required to be open. Components must be properly cleaned before they are installed in boilers or piping systems. Care must also be taken to avoid contaminating treatment chemicals and to ensure the right chemicals are always used. **NSTM Chapter 505 (9480), Piping Systems** , gives guidance for cleaning of piping systems.

220-21.70 CONTROL OF FEEDWATER CONTAMINANTS.

Feedwater conditions must be controlled if corrosion and scale in the feed system are to be minimized. More importantly, corrosion, scale, various deposits, and carryover in high-pressure boiler systems will advance if feedwater purity is neglected. Boiler water treatment provides protection for the boiler against feed system upsets from contamination. It does not replace proper pre-boiler plant operation. Feedwater having low concentrations of dissolved and suspended solids, with oxygen eliminated, is considered good quality feedwater. This type of feedwater can be obtained when all units in the pre-boiler system are functioning properly. Section 22 specifies maximum contamination levels allowed for various feed system waters.

220-21.71 Contaminant Testing.

The quality of feedwater is determined by testing samples from various points in the system for chloride, conductivity, salinity, hardness, dissolved oxygen, and pH. The tests required are governed by the equipment installed. Chloride measures seawater contamination. Conductivity and salinity both indicate sea and shore water contamination. Hardness determinations will detect shore water more rapidly than the chloride test will. A dissolved oxygen sample from the DFT indicates the condition of the DFT by measuring the oxygen level of the DFT discharge. The corrosiveness of the water is related to pH. All of these tests are necessary for rapid location and correction of contaminant sources.

220-21.72 Chelant Boiler/Feedwater Treatment.

Chelant treatment is injected at the DFT. At boiler operating temperatures, part of the treatment decomposes to produce an alkaline steam, thereby reducing corrosion in the condensate and deaerated feedwater lines of the pre-boiler system. Pre-boiler system corrosion is caused principally by the reaction of carbon dioxide (CO_2) with the water in which it is dissolved. The carbon dioxide originates from two sources. Air containing carbon dioxide can enter at almost all points in the pre-boiler system; however, the principal source for carbon dioxide is bicarbonate ion in seawater which is released when heated in distilling plants, thereby acidifying reserve feedwater.

220-21.73

Seawater and shore water are the major contributors of bicarbonate. Carbon dioxide reacts with water forming carbonic acid (H_2CO_3) which decreases the pH, making the water more acidic. By raising the pH or alkalinity of the condensate and deaerated feedwater, corrosion in these parts of the pre-boiler system is reduced.

220-21.74 Demineralization of Makeup Feed.

Makeup feed of very high purity is produced by the use of a demineralizer. When taking on makeup feed, reserve feedwater is passed through a demineralizer containing mixed bed ion exchange resin. The mixed bed ion exchange resin consists of a chemically balanced mixture of both cation exchange resins and anion exchange resins. The cation exchange resin, whose surface is rich in hydrogen ions (H^{+}), exchanges with cations such as magnesium (Mg^{2+}) and calcium (Ca^{2+}). The anion exchange resin, whose surface is rich in hydroxyl ions (OH^{-}), exchanges with anions such as chloride (Cl^{-}) and sulfate (SO_4^{2-}). As the water passes over the mixed bed ion exchange resin, the dissolved cations and anions exchange with the hydrogen and hydroxyl ions and become attached to the exchange resins. The hydrogen ions displaced from the cation exchange resin combine with the hydroxyl ions displaced from the anion resin to form water (HOH). The mixed bed ion exchange resin removes all the cations and anions from the reserve feedwater and exchanges them for pure water. Besides removing the ions, the resin acts as a filter medium to remove the suspended solids from the reserve feedwater. This demineralization (also called deionization) is an extremely useful process since it appreciably reduces the rate of sludge buildup in the boiler water. As the resin bed exhausts its exchange capacity, the makeup feed conductivity will quickly rise above 1.0 µmho/cm indicating that the resin is spent and has to be replaced. If the reserve feedwater has a consistently high suspended solids content, the filtration action may clog the resin bed making premature removal of the resin necessary.

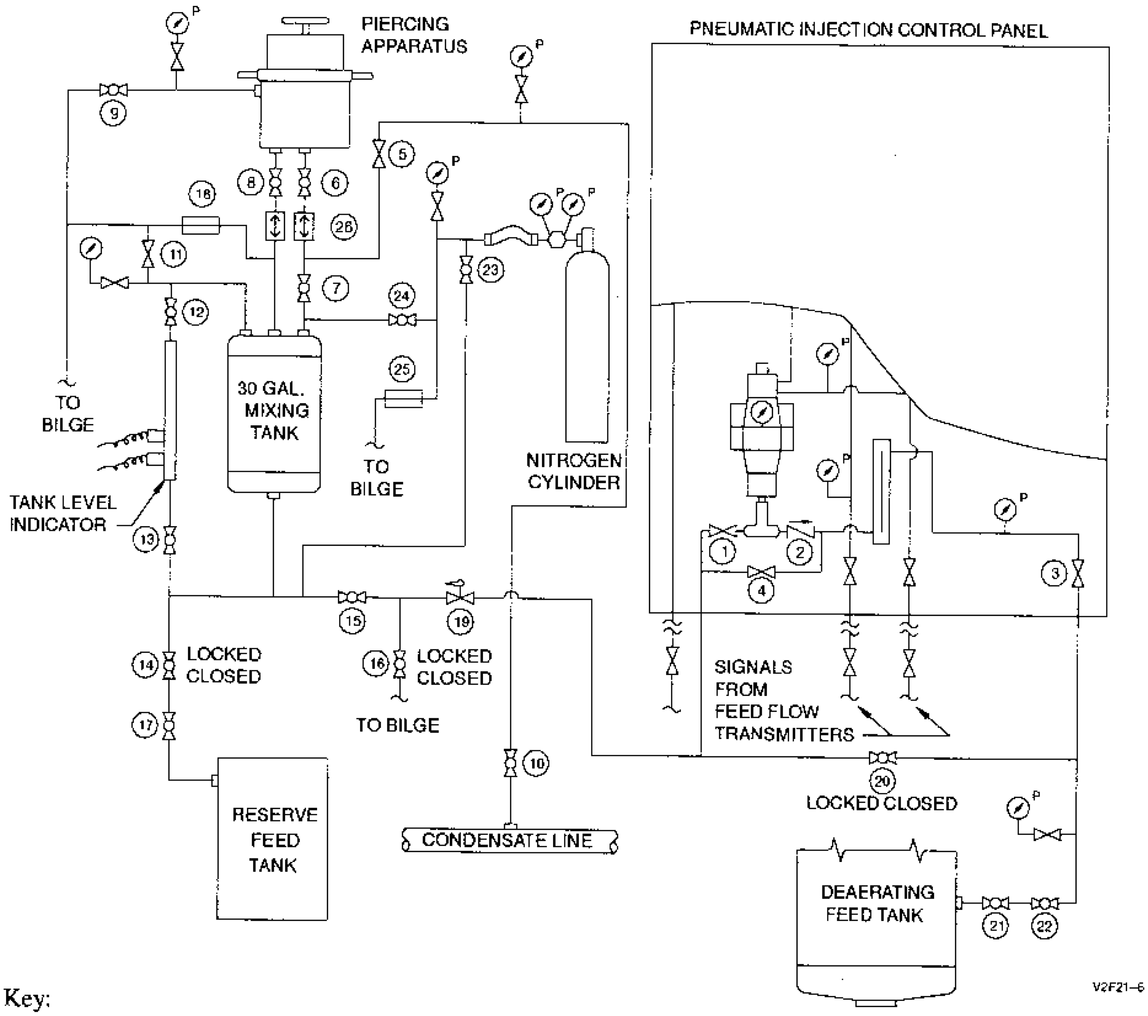
220-21.75 BOILER WATER CONTROL

220-21.76

The boiler acts as a receiver for all of the materials which the feed system pours into it. Only the water leaves the boiler (unless carryover is occurring). All contaminants remain behind to advance the damaging conditions (corrosion, scale formation, and carryover) already discussed. In order to minimize damage, boiler water treatment programs have been established.

220-21.77 CHELANT BOILER FEEDWATER TREATMENT.

Chelant boiler feedwater treatment uses an automated treatment system to continuously inject treatment solution into the DFT. The treatment system is shown in Figure 220-21-6. The treatment solution is prepared using trisodium EDTA, hydrazine and trisodium or disodium phosphate. Trisodium phosphate is used in 600 psig boilers, while disodium phosphate is used in 1200 psig boilers. The treatment solution prepared from these chemicals is automatically injected into the DFT at a rate which is proportional to the feedwater flow based on a signal from the feed flow transmitter. Sodium phosphate is added to maintain a phosphate residual in the boiler water as protection against excessive contamination. The continuous treatment system consists of a piercing apparatus, a mixing tank and a control panel. The piercing apparatus is used to add the chemicals to the mixing tank. The EDTA and the sodium phosphate are dissolved in hot feedwater and then poured into the open piercing apparatus and allowed to drain into the mixing tank. The sealed hydrazine bottle is then placed in the piercing apparatus, the piercing apparatus is closed and the hydrazone bottle is pierced by knife blades within the piercing apparatus. After the hydrazine solution has drained into the mixing tank, condensate is used to flush the bottle and fill the mixing tank to 30 gallons. This treatment solution is then placed under nitrogen pressure and fed to the DFT. The control panel meters the flow of the treatment solution into the DFT proportionally to the feedflow transmitter signals from all of the boilers in the space.



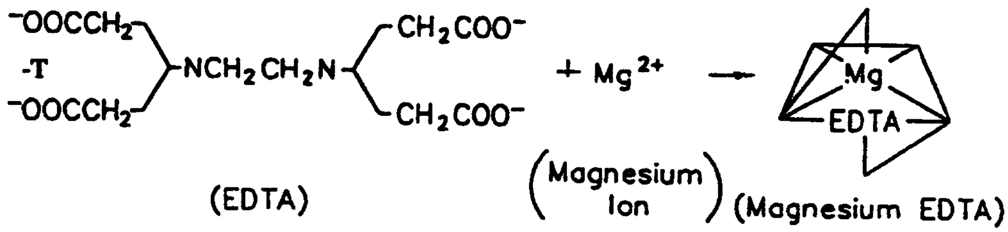
Key:

1. Automated Control Cutout Valve
2. Control Panel Check Valve
3. Treatment Cutout Valve
4. Automated Control Bypass Valve
5. Condensate Flush/Fill Local Cutout Valve
6. Piercing Apparatus Condensate Flushing Cutout Valve
7. Mixing Tank Fill Cutout Valve
8. Piercing Apparatus Drain Cutout Valve To Mixing Tank
9. Piercing Apparatus Vent Cutout Valve
10. Condensate Flush/Fill Root Valve
11. Mixing Tank Vent Cutout Valve
12. Tank Level Indicator Cutout Valve
13. Tank Level Indicator Drain Cutout Valve
14. Hydrazine Supply For Boiler Layup Cutout Valve
15. Hydrazine Supply To Control Panel Cutout Valve
16. Hydrazine Injection System Drain Cutout Valve
17. Hydrazine Supply To Reserve Feedwater Cutout Valve
18. Mixing Tank Relief Valve (Set At 100 PSIG)
19. Solenoid Valve (Closes At 2 Gallon Level)
20. Hydrazine Supply To Control Panel Bypass Valve
21. Hydrazine Supply To Deaerating Feed Tank Cutout Valve
22. Hydrazine Supply To Deaerating Feed Tank Cutout Valve
23. Nitrogen Chemical Mixing Cutout Valve
24. Nitrogen Supply To Mixing Tank Cutout Valve
25. Nitrogen Relief Valve (Set AT 100 PSI)
26. Flow Sights

Figure 220-21-6. Continuous Automated Boiler Feedwater Treatment System.

220-21.78

EDTA is one of a class of organic chemicals known as chelating agents or chelants. The term EDTA for boiler feedwater treatment refers to trisodium ethylenediaminetetraacetate trihydrate ($C_{10}H_{13}N_2Na_3O_8 \bullet 3H_2O$). Other forms of EDTA are tetrasodium EDTA, used for boiler waterside cleaning, and disodium EDTA, used in the hardness test titrant. These chemicals are characterized by a specific type of reaction known as chelation. EDTA chelates dissolved metals, including the scale formers magnesium and calcium, by surrounding and bonding to the metal at several places. The reaction is:



Thus, magnesium and calcium are prevented from forming scale on the boiler tube surfaces. Since the metal chelates remain dissolved, they do not contribute to sludge formation in the boiler. The metal chelates are removed from the boiler by continuous blowdown. Other dissolved metals from feedwater system corrosion and erosion products also react with EDTA. This further reduces the amount of sludge formed in the boiler.

220-21.79

Another important property of EDTA is its ability to generate a protective film of magnetite on steel surfaces. This protective layer forms directly in place and serves to prevent corrosion of the base metal. Unlike other boiler water treatments where magnetite forms primarily as a result of temperature, EDTA directly participates in the rapid formation of a continuous film of magnetite crystals that provide excellent protection to the base metal.

220-21.80

Untreated feedwater and condensate are slightly acidic due mostly to the absorption of carbon dioxide from the air. This acidity increases pre-boiler system corrosion. Neutralizing amines, condensate and feedwater slightly alkaline. Free EDTA (EDTA that has not reacted to form metal chelates) decomposes or hydrolyzes at boiler temperatures. An alkaline, volatile product is produced which acts as a feedwater treatment similar to morpholine. The breakdown product volatilizes with the steam and is returned to the boiler with the feedwater to be recycled. Build up is controlled by losses which occur via the air ejectors, DFT vents and leaks. EDTA also decomposes in the presence of dissolved oxygen. Solutions of EDTA at low concentrations must be protected from dissolved oxygen through the use of an oxygen scavenger.

220-21.81

Catalyzed hydrazine is an alkaline, inorganic chemical used in boiler feedwater treatment as an oxygen scavenger. The catalyst is an organic chemical added to increase the rate of reaction between hydrazine and oxygen. The small amount of oxygen that remains in feedwater after deaeration in the DFT still causes corrosion of boiler metals, particularly the economizer tubes. The use of hydrazine, with a properly functioning DFT, results in elimination of the dissolved oxygen. The reaction is:

$$\underset{\text{(hydrazine)}}{N_2H_4} + \underset{\text{(oxygen)}}{O_2} \rightarrow \underset{\text{(water)}}{2H_2O} + \underset{\text{(nitrogen)}}{N_2}$$

The products of the reaction are nitrogen and water which do not contribute to the dissolved solids level of the boiler water. Hydrazine also converts iron rust (hematite) to magnetic iron oxide (magnetite).

$$\underset{\text{(hematite)}}{6Fe_2O_3} + \underset{\text{(hydrazine)}}{N_2H_4} \rightarrow \underset{\text{(magnetite)}}{4Fe_3O_4} + \underset{\text{(water)}}{2H_2O} + \underset{\text{(nitrogen)}}{N_2}$$

Thus hydrazine will enhance the protective magnetite layer that acts as a barrier to corrosion. Hydrazine is volatile and does not concentrate to an appreciable amount in the boiler water. Hydrazine decomposes to ammonia at temperatures over 600°F. Therefore, any hydrazine that volatilizes with the steam will be thermally decomposed in the superheater.

$$\underset{\text{(hydrazine)}}{3N_2H_4} \underset{\text{heat}}{\xrightarrow{\Delta}} \underset{\text{(ammonia)}}{4NH_3} + \underset{\text{(nitrogen)}}{N_2}$$

High levels of ammonia in steam can be corrosive to the copper alloys found in the condensate system when oxygen is also present. Therefore, the treatment level of hydrazine is maintained with only a slight excess of that required to eliminate the residual dissolved oxygen.

220-21.82 CHELANT BOILER WATER CONTROL.

The goals of successful boiler water treatment are to prevent scale formation and to minimize corrosion and carryover. The primary control of the boiler water using the chelant treatment is accomplished with the continuous treatment system. Batch chemical injection is only used to adjust chemical levels for initial treatment and during contamination incidents. Since chelant is continuously injected, continuous blowdown is required to prevent excessive buildup of treatment chemicals, as well as to remove the chelated contaminants. This is accomplished using a low, controlled flow of boiler water through the sample cooler to the bilge. Continuous blowdown amounts to about a 4 percent blowdown daily between 20 and 60 percent boiler load.

220-21.83

Scale prevention, with good quality feedwater, is controlled by the reaction of EDTA with magnesium and calcium before entering the boiler, as discussed in paragraph 220-21.78. Scale prevention during higher levels of contamination, that exceed the available EDTA, is accomplished by the alkaline boiler water with a residual phosphate level. In this case, the magnesium and the calcium form precipitates.

$$\underset{\text{(magnesium ion)}}{Mg^{2+}} + \underset{\text{(hydroxyl ion)}}{2OH^-} \rightarrow \underset{\text{(magnesium hydroxide)}}{Mg(OH)_2\downarrow}$$

$$\underset{\text{(calcium chloride)}}{5CaCl_2} + \underset{\text{(disodium phosphate)}}{3Na_2HPO_4} + \underset{\text{(sodium hydroxide)}}{4NaOH} \rightarrow \underset{\text{(hydroxyapatite)}}{Ca_5(OH)(PO_4)_3\downarrow} + \underset{\text{(sodium chloride)}}{10NaCl} + \underset{\text{(water)}}{3HOH}$$

$$\underset{\text{(magnesium chloride)}}{3MgCl_2} + \underset{\text{(disodium phosphate)}}{2Na_2HPO_4} + \underset{\text{(sodium hydroxide)}}{2NaOH} \rightarrow \underset{\text{(magnesium phosphate)}}{Mg_3(PO_4)_2\downarrow} + \underset{\text{(sodium chloride)}}{6NaCl} + \underset{\text{(water)}}{2HOH}$$

$$\underset{\text{(calcium (chloride)}}{3CaCl_2} + \underset{\text{(disodium phosphate)}}{2Na_2HPO_4} + \underset{\text{(sodium hydroxide)}}{2NaOH} \rightarrow \underset{\text{(calcium phosphate)}}{Ca_3(PO_4)_2\downarrow} + \underset{\text{(sodium chloride)}}{6NaCl} + \underset{\text{(water)}}{2HOH}$$

220-21.84

Sludge in boiler water is an agglomeration of reaction products of boiler water treatment chemicals with calcium and magnesium contaminants and also includes the suspended matter entering with the feedwater. A chemical analysis of a typical sludge is given in Table 220-21-2. Sludge, if allowed to accumulate in the headers and water drum, will reach so large an amount that particles will circulate with the boiler water. As sludge circulates, it begins to adhere physically to the generating surfaces. The adhering sludge is at first soft and is removable by mechanical cleaning. If allowed to remain on generating surfaces, the soft sludge is converted by heat to hard, baked-on sludge. The baked-on sludge is physically different from scale (scale forms in place; sludge is carried to high heat transfer areas) but it acts just like scale in that it restricts heat transfer with resulting blistering of the tube and eventual rupture. It also causes chemical concentrations as described in paragraph 220-21.27. Mechanical cleaning of the watersides will not remove baked-on sludge or scale. Scale is prevented by proper chemical treatment. Sludge is kept low in concentration by maintaining feedwater purity, by ensuring that chelant treatment is continuously used, and by effective blowdown including both surface and continuous blowdown as well as bottom blowdown on a secured boiler.

Table 220-21-2. WATERSIDE DEPOSIT CHEMICAL ANALYSIS (TYPICAL)

Constituent	Reported As	Percent
Iron	$Fe_3 O_4$	63.4
Magnesium	MgO	1.6
Calcium	CaO	1.4
Phosphorus	$P_2 O_5$	3.2
Copper	CuO	24.8
Nickel	NiO	0.8

Table 220-21-2. WATERSIDE DEPOSIT CHEMICAL ANALYSIS

(TYPICAL) - Continued

Constituent	Reported As	Percent
Zinc	ZnO	0.9
Sulfur	SO_3	<0.1
Silica	SiO_2	<0.1
Carbonaceous Matter	Loss on Ignition	<0.1

220-21.85

The corrosion rate for boiler metal is minimized when the boiler water is maintained in a moderately alkaline region. Three chemicals are used to provide the alkalinity under chelant treatment: trisodium EDTA, trisodium phosphate and sodium hydroxide (caustic soda). Under normal conditions with good quality feedwater the continuous treatment solution maintains the required alkalinity. Trisodium EDTA forms alkaline solutions with water. This provides some of the required alkalinity. When free EDTA decomposes at boiler temperatures the alkalinity of the boiler water is increased. In 600 psig boilers the EDTA decomposition products do not provide sufficient alkalinity. Trisodium phosphate is used in the continuous treatment solution fed to 600 psi boilers to provide the required alkalinity. At 1200 psig the breakdown of EDTA provides sufficient alkalinity. Therefore, disodium phosphate is added to the continuous treatment solution fed to 1200 psi boilers to provide the phosphate backup without additional alkalinity. Usually, chemical additions using the batch chemical injection tank, are only used to provide alkalinity and phosphate for a freshly filled boiler and to adjust boiler chemistry during contamination. Initial treatment is accomplished using trisodium phosphate alone to provide the alkalimity as well as the phosphate. When the boiler water alkalinity or phosphate is depleted by serious contamination, batch treatment with trisodium phosphate or caustic soda is required to restore proper alkalinity levels.

220-21.86

Chelant treatment does not maintain the boiler water parameters under the coordinated phosphate curve. Phosphate levels required to maintain boiler water parameters under the curve cannot be used with chelant treatment. At high phosphate levels used in COPHOS treatment, the scale formers would react with the phosphate rather that the EDTA, and the sludge produced would cause waterside deposits and eventually require waterside cleaning. Therefore, low phosphate levels must be maintained with chelant treatment. Caustic corrosion does not occur with chelant treatment at normal treatment levels due to the enhanced magnetite film formed through the reaction between EDTA and the steel surfaces. If boiler water alkalinity becomes excessive, caustic corrosion may still occur. High levels of alkalinity are controlled by blowdown.

220-21.87

Overtreatment with EDTA has been reported to cause chelant corrosion. EDTA dosage has been calculated to be slightly higher than the expected feedwater contamination level. Excessive amounts of EDTA can cause corrosion of feed system piping and boiler metal surfaces. Under no circumstances should more EDTA than specified in the dosage table be added to the treatment tank. EDTA shall not be injected using the batch treatment system under any circumstances. Only the continuous injection system may be used for EDTA/hydrazine treatment.

220-21.88

Carryover of the boiler water with the steam is minimized by control of the dissolved and suspended solids level in the boiler water. Under normal conditions continuous blowdown maintains the dissolved solids level within limits. Higher levels of dissolved solids, due to contamination or overtreatment, are controlled by surface blowdown. Since chelant treatment is not a precipitation treatment, the amount of suspended solids found in the boiler is greatly reduced. However, other sources of suspended solids such as dirt and debris, remain essentially unchanged and are controlled by bottom blowdown. Continuous blowdown provides for some elimination of suspended solids.

220-21.89

Operating ships using chelant treatment shall not use sodium nitrite. Hydrazine and sodium nitrite are incompatible. Operating ships using chelant treatment use hydrazine/morpholine for wet layup and feed quality water for hydrostatic testing.

220-21.90

IMA and industrial activities are authorized to use sodium nitrite in chelant treated ships for water jet cleaning, hydrostatic tests, wet layup and prior to dry layup. Chelant treated boilers must be completely drained of all hydrazine treated water prior to using sodium nitrite. Sodium nitrite treated boilers must be dumped and flushed once with feed quality water to remove residual sodium nitrite prior to application of chelant treatment or hydrazine/morpholine layup.

220-21.91 Effect of Seawater on Boiler Water Chemicals.

When seawater enters boiler water, it carries with it four indicators: magnesium, calcium, chloride, and conductivity. Because of the large amount of magnesium, the chemical reaction causes alkalinity to drop. Both magnesium and calcium will cause phosphate to decrease because of the formation of sludge containing phosphate. Chloride and conductivity will increase.

220-21.92

As a matter of interest, addition of salt alone, sodium chloride, will increase chloride and conductivity but will not affect alkalinity or phosphate. It is not sodium chloride nor chloride per se which causes scale formation or acid attack.

220-21.93 Effect of Shore Water on Boiler Water Chemicals.

Shore water has one major indicator, calcium. The relatively large amount of calcium in shore water in comparison to magnesium causes phosphate to decrease. The alkalinity will increase. Conductivity will slowly increase. Chloride may not change.

220-21.94 Chemical Hideout.

The phenomenon of chemical hideout disrupts control of boiler water treatment. Chemical hideout is usually evidenced by a diminishing level of phosphate as boiler steaming rate increases. Phosphate returns when the steaming rate decreases or when the boiler is secured. The reasons for its occurrence are not well defined, but two likely mechanisms have considerable data to support them. One mechanism shows that circumstances must allow concentration of chemicals. The other shows that reaction with the magnetite protective layer occurs.

220-21.95

If tube surfaces are smooth and free of deposits, boiler water circulates freely and is effective in continuously washing tube metal. Porous deposits, crevices, pits and leakage sites interfere with circulation creating areas conducive to concentration of boiler water. All of the normally soluble chemicals concentrate. If the interference is severe, localized dry-out of boiler water treatment chemicals and contaminants can occur. Sodium chloride is more soluble in high-temperature water than trisodium phosphate which is more soluble than disodium phosphate. When such localized concentration of boiler water is occurring, alkalinity, phosphate, and conductivity decrease. A decrease in chloride may or may not be detected. As heat input to the boiler tubes increases, the concentrating effect at the metal increases. As heat transfer rate decreases, the chemicals return to the bulk boiler water.

220-21.96

Reactive hideout occurs when the phosphate reacts directly with magnetite ($Fe_3 O_4$) to form a solid sodium iron phosphate compound. This is a high-temperature reaction and the compound decomposes when temperatures are reduced. If reaction with magnetite is occurring, alkalinity increases and phosphate decreases as steaming rate increases. The reverse occurs when steaming rate decreases or the boiler is secured.

220-21.97

Many instances of chemical hideout in naval propulsion boilers are reported after the following events have occurred:

1. Acid cleaning.
2. EDTA cleaning.
3. A contamination incident.

The events can all cause disruption of magnetite or generation of deposits in the boiler and the appearance of hideout. Mechanical cleaning (via water-jet) alleviates the condition when caused by soft deposits. If contamination has caused hard deposits, only acid cleaning will remove them. Hard deposits represent a hazard to boiler operation and in themselves cause hideout.

220-21.98

The reason for development of hideout soon after acid cleaning is not clear, but either or both of the previously described mechanisms may be at work when sensitized metal surfaces and soft deposits are present.

220-21.99 BLOWDOWN.

Blowdown provides control of accumulated boiler water solids, both suspended and dissolved.

220-21.100 Surface Blowdown.

Surface blowdown serves the purpose of reducing the amounts of materials dissolved in the boiler water. Contamination and treatment chemicals both contribute to the dissolved materials, and the total amounts of them are measured by conductivity. Surface blowdown routinely controls conductivity within limits. If contamination or chemical overaddition causes alkalinity or phosphate to exceed upper control limits, both are reduced by surface blowdown.

220-21.101 Scum Blowdown.

Surface blowdown also removes some suspended solids and oil. Oil can be removed effectively only blowing down to the surface blow pipe. Refer to paragraph 220-22.52 for detailed surface blowdown procedures.

220-21.102 Continuous Blowdown.

Continuous blowdown is used primarily to rid the boiler of dissolved metal chelates and suspended matter. At the same time, boiler water conductivity is also being monitored. Refer to paragraph 220-22.55 for detailed procedures.

220-21.103 Bottom Blowdown.

The amount of sludge in the boiler is normally controlled by bottom blowdown. For a bottom blowdown to be most effective, the boiler should be secured as long as possible but not more than 24 hours prior to initiation of the blowdown. If the boiler is being secured for bottom blowdown and is then to be returned to the line, the blowdown is to be initiated when the boiler has been secured for at least 1 hour.

220-21.104

In a boiler with proper chemical treatment, the amount of sludge produced over a specified steaming period is dependent upon the amount of makeup feedwater, the quality of the makeup feedwater, and the overall level of seawater and shore water contamination of the feedwater. The appearance of a boiler water sample by itself is not an indicator of whether a boiler does or does not need a bottom blowdown. A properly obtained boiler water sample is representative only of the dissolved material present in the boiler water, not the suspended matter or sludge in the boiler. Refer to paragraph 220-22.59 for detailed bottom blowdown procedures.

220-21.105 IDLE BOILER MAINTENANCE.

The primary consideration of idle boiler maintenance is the prevention of oxygen corrosion of the boiler metal. Wet iron exposed to air (oxygen) will corrode. Elimination of the corrosion of the iron can be accomplished by removing either the air or the moisture. There are two forms of idle boiler layup: dry and wet. For detailed procedures on idle boiler layup refer to **NSTM Chapter 221, Boilers** . Wet layup methods used for idle boiler care were developed to eliminate atmospheric oxygen and the possibility of oxygen pitting of boiler watersides. Both the steam blanket and nitrogen blanket utilize a steam and nitrogen supply, respectively, to maintain an oxygen-free environment in the boiler that has just been secured. A positive pressure must be maintained in order to prevent any oxygen penetration into the boiler. The hot deaerated fill operates under the same principle but is less effective. Rather than eliminating oxygen contamination, the sodium nitrite method uses a corrosion inhibitor to eliminate corrosion provided that a uniform mixture of the solution has been used. If the sodium nitrite layup solution does not have a uniform concentration throughout the boiler, corrosion can occur. Care must be taken when using nitrite to prevent feed system contamination by the layup solution and to remove all of the layup solution from the boiler prior to boiler operation. Otherwise, high alkalinity in boiler water will occur upon boiler light-off. The hydrazine/morpholine layup uses hydrazine, an oxygen scavenger which depletes dissolved oxygen. Morpholine, a volatile chemical, is employed to maintain pH in the alkaline range in order to facilitate the reaction between hydrazine and oxygen.

SECTION 22.

WATER REQUIREMENTS FOR PROPULSION BOILER SYSTEMS

220-22.1 REQUIREMENTS FOR CHELANT TREATMENT OF PROPULSION BOILER FEEDWATER

220-22.2

The feedwater requirements for propulsion boiler systems are based on a boiler water concentration factor of 10. This assumes that if a boiler is steaming at 50 percent load, the water in the boiler will concentrate all feedwater contaminants 10 times an hour. If deaerated feedwater contains the maximum 0.02 epm chloride, the boiler water will increase by 0.2 epm chloride each hour. If there is a constant rate of seawater contamination entering the condensate system, boiler water contamination will increase at a constant rate regardless of boiler load.

220-22.3

The established feedwater limits are maximal. All plants can and should operate considerably below these limits. The feedwater limits specify those levels at which it will be possible to maintain control of boiler water alkalinity, phosphate, chloride, and conductivity during a normal boiler water sampling cycle.

220-22.4

In order to locate, isolate, and correct contaminant sources, plant operating personnel must be alert to **increases** in salinity indicator and conductivity cell readings. The maximum limits for various feedwaters should not be considered desirable for continuous operation. Readings should be maintained at the lowest possible level for routine control of boiler water.

220-22.5

The sampling and testing requirements and the maximum limits for the various feedwater components are listed in paragraphs 220-22.6 through 220-22.24. Ships with demineralizers must follow the requirements of paragraph 220-22.26 for reserve and makeup feedwater. All requirements are summarized in Table 220-22-1 and 220-22–2. A log of feedwater conditions shall be maintained in accordance with Section 27.

220-22.6 CHEMICAL TESTS AND SALINITY/CONDUCTIVITY INDICATOR COMPARISON.

All salinity/conductivity indicators that monitor distillate, makeup feed (excluding demineralizer outlet), main and auxiliary condensates (excluding distiller air ejector drains), low-pressure and freshwater drains, and deaerated feedwater shall be checked daily whenever a feedwater system is on-line, to ensure satisfactory operation of the salinity/conductivity indicator. Ships equipped with conductivity indicators which read out in micromhos per centimeter (µmho/cm) are required to convert the µmho/cm readings to epm chloride prior to making the comparison. To convert µmho/cm to epm chloride, divide the conductivity readings by 145 (for example, 2.90 µmho/cm divided by 145 µmho/cm/epm equals 0.02 epm chloride). This check shall be made by comparing the chemical test result for feedwater chloride to the salinity/conductivity indicator reading.

1. If the difference between the chemical test result and the salinity/conductivity indicator reading is 0.02 or less, the comparison is satisfactory.
2. If the chemical test result is higher than the salinity/conductivity indicator reading by more than 0.02, the comparison is unsatisfactory and the salinity/conductivity indicator must be checked for malfunction (paragraph 220-24.70).
3. If the chemical chloride test result is lower than the salinity indicator reading by more than 0.02 epm, check the water for hardness (excluding distillate) [*] . If hardness is 0.02 epm or less, check the indicator for malfunction. If the hardness is more than 0.02 epm, the indicator is functioning satisfactorily.
4. An indicator that consistently reads zero shall be checked for malfunction.

[*]The comparison test for distillate is based only on chemical chloride because distillate is not affected by morpholine and hardness testing may give false high results. If the chemical chloride test result is lower than the salinity or conductivity indicator by more than 0.02 epm, check the indicator for malfunction.

NOTE

Salinity or conductivity indicator readings higher than chemical chloride may also occur due to the presence of dissolved gases when operating in coastal, river, bay or port waters, or due to volatile chemicals following hydrazine layup or use of shore steam. If high salinity/conductivity indicator readings for distillate or distiller air ejector drains continue in the absence of high chemical chloride when operating in coastal, river, bay or port waters for extended periods, the following applies:

a. Test for chemical chloride every four hours.

b. Use of the water is based on chemical chloride.

c. Salinity/conductivity indicator limit/alarm set point/dump set point may be set to a value just above the distillate/air ejector drain salinity/conductivity. Record time/alarm set point in Remarks section of Feedwater Log.

d. Reset salinity/conductivity indicator limit/alarm set point/dump set point to normal values when indicator readings return to normal limits. Record in the remarks section of the feedwater log.

220-22.7

Any chemical test result for chloride or hardness, which exceeds maximum contamination limits, requires isolation of the contamination source. Sample and test any steaming boiler that could be affected by the contamination. Appropriate treatment action will be based on the test results. Monitor the boiler continuous conductivity meter for evidence of contamination. This applies whether the out-of-limits condition was discovered during salinity/conductivity indicator checks or under other circumstances.

220-22.8

Comparison test requirements and examples are listed in Table 220-22-1. Sampling of the water and reading of the salinity or conductivity indicator should be accomplished concurrently.

220-22.9

If feedwater quality (DFT outlet or similar monitoring point) can not be continuously monitored by salinity or conductivity indicator, boiler water shall be sampled and tested every four hours. Whenever a salinity or conductivity indicator which monitors points other than feedwater is malfunctioning, the water that is monitored by the affected indicator shall be sampled and chemically tested for chloride (paragraph 220-22.17) at least every four hours until the indicator is returned to service (except that reserve feed is chemically tested for chloride within 30 minutes prior to placing a tank on makeup).

220-22.10 DISTILLATE.

The salinity of all distillate, measured by salinity indicator, shall not exceed 0.065 epm. If conductivity indicators are installed, conductivity shall not exceed 10 µmho/cm. The limit by chemical test for distillate discharging to reserve feed is 0.07 epm chloride. Hardness test is not accomplished on distillate because distillate may contain bicarbonate which interferes with the hardness test causing false high results. Modern distilling units have a solenoid-controlled dump valve on the distillate discharge line, actuated by a salinity or conductivity cell that continuously monitors distillate quality. A two-compartment measuring tank for distillate is provided on some ships of older construction. A chemical test for the chloride content (paragraph 220-26.17) shall be performed prior to transferring water from either compartment of the measuring tank.

The acceptability of the chemical tests and salinity/conductivity indicator comparison is based on the difference between the results obtained by performing the feedwater chloride test (CH) and reading the salinity indicator (SI) or conductivity indicator (CC). Action taken depends on this difference. The comparison tests shall be performed daily on all feedwater monitored by salinity and conductivity indicators, in accordance with paragraph 220-22.6, whenever a feedwater system is on-line.

Table 220-22-1. CHEMICAL TESTS AND SALINITY/CONDUCTIVITY INDICATOR COMPARISON

The acceptability of the chemical tests and salinity/conductivity indicator comparison is based on the difference between the results obtained by performing the feedwater chloride test (CH) and reading the salinity indicator (SI) of conductivity indicator (CC). Action taken depends in this difference. The comparison tests shall be performed daily on all feedwater monitored by salinity and conductivity indicators, in accordance with paragraph 220-22.6, whenever a feedwater system is on-line.		
CL-SI (epm)	**Comparison**	**Action**
0 to ± 0.02	Sat	A. None
Chemical test is higher by more than 0.02	Unsat	B. Check salinity/conductivity indicator (para. 220-24.70 through 220-24.75)
Chemical test is lower by more than 0.02	Unsat	C. Check hardness and follow para. 220-22.6.3.

Table 220-22-1. CHEMICAL TESTS AND SALINITY/CONDUCTIVITY INDICATOR COMPARISON EXAMPLES

EXAMPLES				
Feedwater Chloride Test Result (CH) (epm)	**Salinity/Conductivity Indicator Reading (SI)/(CC) (epm)/(μmho/cm)**	**CH-SI (epm)**	**Comparison**	**Action**
0.10	0.120/17.5	-0.020	Sat	A
0.12	0.120/17.5	0.000	Sat	A
0.15	0.120/17.5	+0.030	Unsat	B
0.07	0.120/17.5	-0.050	Unsat	C
0.05	0.065/9.5	-0.015	Sat	A
0.07	0.065/9.5	+0.005	Sat	A
0.10	0.065/9.5	+0.035	Unsat	B
0.02	0.065/9.5	-0.045	Unsat	C

Table 220-22-2. CHELANT BOILER FEEDWATER, REQUIREMENTS SUMMARY

	Maximum Limit.			
Source	**Conductivity Indicator μmho/cm**	**Salinity Indicator epm**	**Chemical Chloride epm**	**Chemical Hardness epm**
Distillate	10.0	0.065	0.07	---
Distiller Air Ejector Drains	10.0	0.065	0.02	---
Reserve Feedwater/Makeup Feedwater	15.0	0.100	0.10	0.10

Table 220-22-2. CHELANT BOILER FEEDWATER, REQUIREMENTS

SUMMARY - Continued

	Maximum Limit.			
Source	**Conductivity Indicator µmho/cm**	**Salinity Indicator epm**	**Chemical Chloride epm**	**Chemical Hardness epm**
Demineralized Makeup Feedwater	1.0	---	---	---
Deaerated Feedwater, Condensate, Drains	3.0	0.020	0.02	0.02
			Dissolved Oxygen ppb	**Hydrazine, ppb (Range)**
Deaerated Feedwater			15	10-40

Source	**Test Frequency**
All distillate, condensate, and feedwater monitored by salinity indicators.	Perform daily comparison test on all salinity indicators that can be sampled (except distiller air ejector drains).
	Monitor indicators whenever system component is operating
	When indicator malfunctions, test affected water for chloride every 4 hours or test boiler water every 4 hours. If DFT outlet cell malfunctions, test boiler water every 4 hours.
Distiller air ejector drains	Test for chloride daily.
	When indicator malfunctions or indicates an out of limits condition, test for chloride every 4 hours. Drains may be used based on chemical chloride test.
Reserve and makeup feedwater	Test all unused feedwater tanks daily for chloride and hardness while steaming.
	For cold plant start-up, test first reserve feedwater tank for chloride within 30 minutes prior to use.
	Monitor salinity or conductivity indicator or demineralizer inlet cell as soon as feed tank is placed on makeup.
	When indicator is faulty, test each reserve feedwater tank for chloride within 30 minutes prior to use.
	When demineralizer is in use, monitor outlet conductivity cell.
Deaerated feedwater	Dissolved Oxygen: Prior to feeding boiler, 2-3 hours after boiler is on-line, and daily.
	Hydrazine: 8-10 hours after start of treatment, daily, and within 4 hours of out of limits result.
Service steam (low pressure)	Test for chloride and hardness prior to aligning to FWDCT.
	In-port test for chloride and hardness daily when aligned to FWDCT.

NOTE

Salinity indicator alarm and dump valves shall be set as close to the above limits as installed hardware permits. Replacement or modifications of installed hardware is not authorized or required by this chapter. Updating of these systems is only approved by ship alteration as authorized by the Type Commander and NSWCCD on the distillate discharge line, actuated by a salinity or conductivity cell that continuously monitors distillate quality. A two-compartment measuring tank for distillate is provided on some ships of older construction. A chemical test for the chloride content (paragraph 220-26.17) shall be performed prior to transferring water from either compartment of the measuring tank.

220-22.11 RESERVE AND MAKEUP FEEDWATER.

Daily chemical tests for chloride and hardness shall be performed on reserve feedwater in those tanks which have not been used for 24 hours while steaming. The chloride content by the chemical test shall not exceed 0.10 epm, and the hardness content shall not exceed 0.10 epm. Reserve feedwater not meeting these requirements shall be dumped. **The blending of water from two tanks, one exceeding the requirements and one within the requirements (or any other version of sweetening), is prohibited** . For cold plant startup, sample the first reserve feed tank that is to be placed on makeup within 30 minutes prior to use, and chemically test for chloride. As soon as the tank is on-line, read the salinity/conductivity indicator and compare the reading to the chemical test result. Each 24 steaming hours thereafter, sample the feed tank that is on makeup, while concurrently reading the salinity/conductivity indicator. Perform the chloride and comparison test. The makeup feedwater salinity/conductivity indicator shall be monitored immediately after any reserve feedwater tank is placed on suction. The salinity indicator reading shall not exceed 0.10 epm. If conductivity indicators are installed, the conductivity shall not exceed 15 µmho/cm. When the salinity/conductivity indicator is faulty, as indicated by the comparison test, a chemical test for chloride is required within 30 minutes prior to placing any reserve feedwater tank on makeup.

220-22.12 MAIN AND AUXILIARY CONDENSATES, DRAINS.

The required daily comparison tests for the condensates and drains will ensure that the salinity/conductivity indicators are functioning properly. Whenever a feedwater system is on-line, the salinity/conductivity indicators of the supporting condensate systems shall be monitored for any indication of contamination. The salinity indicator reading shall not exceed 0.02 epm chloride. If conductivity indicators are installed, the conductivity indicator reading shall not exceed 3 µmho/cm. The chloride and hardness content by chemical test shall not exceed 0.02 epm.

NOTE

Loss of electrical power to the distilling plant will sometimes cause evaporators to flood with seawater. When flooding occurs, feedwater heater condenser drains and air ejector drains may become contaminated. On ships not provided with three-way dump valves on the feed heater or air ejector drains, this seawater contamination may enter the condensate system and/or freshwater drain collecting tank. Therefore, when electrical power is lost, prompt action shall be taken to direct these drains to the bilge.

220-22.13 Service Steam (low pressure).

Hotel drains are a frequent source of hardness contamination from shore water. For this reason, hotel drains shall be sampled and tested for chloride and hardness as follows:

1. Daily while steaming in port with hotel drains aligned to the fresh water drain collecting tank.
2. Prior to alignment of hotel drains to the fresh water drain collecting tank following in-port periods.

220-22.14 Distiller Air Ejector Drains.

The chloride limit by chemical test for distiller air ejector drains is 0.02 epm. Carbon dioxide gas removed from the distilling unit can dissolve in the air ejector drains causing the salinity or conductivity readings to be higher than the actual chloride content. Therefore, the limit by salinity indicator is 0.065 epm or by conductivity indicator is 10 µmho/cm. The daily salinity/conductivity indicator comparison test is not required. The high bicarbonate level can also interfere with the hardness test giving false high results. The hardness test is not accomplished on distiller air ejector drains. A chemical chloride test of distiller air ejector drains is required daily. If the salinity/conductivity indicator malfunctions or indicates an out of limits condition and the drains are being returned to the system, chemically test for chloride every four hours.

220-22.15 DEAERATED FEEDWATER.

The required daily comparison test for deaerated feedwater will ensure that the salinity/conductivity indicator is functioning properly. The chloride and hardness content by chemical test shall not exceed 0.02 epm. The deaerated feedwater shall be monitored by salinity indicator for any indication of contamination. The salinity reading shall not exceed 0.02 epm or 3 µmho/cm. EDTA breaks down in the boiler to provide a volatile, alkaline product that protects the feed system. The effect of this breakdown product on the salinity indicators is minimal.

220-22.16

Deaerated feedwater shall be sampled and chemically tested for dissolved oxygen after DFT warmup prior to feeding the boiler, two to three hours after the boiler is on-line, and daily while on-line. The dissolved oxygen shall not exceed 15 parts per billion (ppb) after DFT warmup prior to feeding the boiler and from two hours after the boiler is on-line until it is secured. This requirement does not apply during the first two hours after the boiler is on-line because condensate and feed system warmup is necessary for proper deaeration after feeding the boiler. While steaming at sea, the dissolved oxygen should be less than 10 ppb.

NOTE

The requirement to test the DFT for dissolved oxygen after DFT warmup, prior to feeding the boiler, does not apply to ships which are not piped to allow DFT recirculation through the DFT spray valves, or to ships that do not have certified shore or ship's steam available.

220-22.17

Deaerated feedwater shall be sampled and tested for hydrazine 8 to 10 hours after the continuous treatment system is on-line and daily thereafter. Catalyzed hydrazine, together with the other treatment chemicals, is continuously fed at a controlled rate to the DFT to obtain a hydrazine range of 10 to 40 ppb in the deaerated feedwater. Results outside of this range indicate the treatment system should be checked for proper operation. Low results may also be caused by a malfunctioning deaerating feed tank due to depletion of the hydrazine by excessive dissolved oxygen. Light off of a boiler after hydrazine/morpholine layup may result in high levels of hydrazine and morpholine. The results will return to normal with continued steaming.

220-22.18 SHORE STEAM AND CONDENSED SHORE STEAM USED AS FEEDWATER.

Steam supplied directly to ships or condensed for use as feedwater shall be generated from feedwater which is either treated with a chemical oxygen scavenger, or mechanically deaerated to a maximum dissolved oxygen content of 15 ppb. Shore steam and condensed shore steam used as feedwater shall meet the following requirements:

Shore Steam Requirements

Constituent or Property	Requirement
pH	8.0 to 9.5

Shore Steam Requirements - Continued

Constituent or Property	Requirement
Conductivity	25 µmho/cm max
Dissolved Silica	0.2 ppm max
Hardness	0.10 epm max
Total Suspended Solids	0.10 ppm max

NOTE

The use of filming amines to control steam/condensate pH is prohibited. Compliance with environmental and health regulations is the responsibility of the shore facility.

220-22.19 NAVY AND COMMERCIAL FACILITY SHORE STEAM CERTIFICATION REQUIREMENTS.

Shore steam provided to Navy ships shall meet the requirements of paragraph 220-22.18. Facilities providing shore steam to Navy ships are required to sample and test shore steam and provide certification to the user ships as follows:

1. Sampling and analysis requirements.
   a. Shore boiler discharge shall be sampled daily.
   b. Each pier and quay shall be sampled quarterly. Shore steam sampling piping arrangements shall comply with part 31 of the American Society for Testing Materials standards and NAVFAC P-200. Steam hoses shall be in accordance with specification MIL-H-29210.
2. Shore steam certification requirements.
   a. Documentation of the most recent daily and quarterly analysis results shall be provided to each ship prior to shore steam hookup.
   b. Daily steam analysis results shall be made available to each ship by telephone. Telephone number shall be provided to each ship at the time of shore steam hookup.
   c. Each ship shall be notified anytime shore steam does not meet the requirements of paragraph 220-22.18.

NOTE

Shore steam not complying with the requirements of paragraph 220-22.18 shall not be used. Violation of the requirements of paragraph 220-22.18 or the above certification requirements shall be reported by message to the Type Commander with info copy to ISIC, NSWCCD-SSES, and NAVSEA.

220-22.20 SHORE PROCESSED FEEDWATER (DEMINERALIZERS, REVERSE OSMOSIS).

Feed-water produced by demineralization, reverse osmosis, or any process other than steam condensation shall meet the following requirements:

Feedwater Requirements

Constituent or Property	Requirement
Conductivity	2.5 µmho/cm max (at point of delivery)
Silica	0.2 ppm max

220-22.21

To ensure that feedwater which is processed from shore water and provided to ships meets the above standards, the facility/contractor shall continuously monitor the conductivity of the feedwater being provided and shall test the feedwater for silica before delivery to each ship. When any test result indicates that the effluent does not meet the above standards, the facility/contractor shall test the water in all ship's feed tanks which received the water. Copies of all test results shall be provided by the facility/contractor to the ship receiving the water.

220-22.22 SHORE SOURCE FEEDWATER REQUIREMENTS.

An analysis shall be obtained from the supplier of the shore steam condensate or feedwater certifying that a sample of the shore steam condensate or feedwater meets the requirements in paragraph 220-22.18 or 220-22.20 as applicable. Prior to supplying water to the ship's feed system, pierside demineralizers shall be flushed to waste, and flowing effluent shall be tested and certified by the supplier (contractor or facility) as meeting the standards of paragraph 220-22.20. This requirement applies any time pierside demineralizers are secured and restarted regardless of how short the time. A manifold system shall be used such that continuous flowing pierside demineralizer effluent can be directed to waste or ship's feed system without interrupting flow through the demineralizer. A 100-mesh Y-type strainer shall be installed in the feed line to the ship to preclude resin contamination of the ship system.

220-22.23

Ship's force shall sample and test each shipment of shore source feedwater for agreement with the following requirements:

Shore Source Feedwater Requirements

Constituent or Property	Requirement
Hardness	0.10 epm max
pH (condensate)	greater than 5.4
pH (processed water)	between 5.4 and 8.2
Silica (propulsion boilers only)	0.20 ppm max
Conductivity	less than 40 µmho/cm*
*The lowest reading on the shipboard conductivity meter is 40 µmho/cm.	

220-22.24

When the feedwater source is a batch delivery, as by tank truck, ship's force shall sample and test the water in each tank prior to acceptance. When the source is a continuous process, as from a shore to ship pipeline or mobile demineralizer, ship's force shall sample and test the water prior to entry into ship's systems, at the anticipated delivery midpoint, and prior to securing from receiving water. The requirements listed in paragraph 220-22.23 apply. The midpoint and final samples should be tested for silica only.

220-22.25 MAKEUP FEEDWATER DEMINERALIZER SYSTEM

220-22.26

The quality of feedwater is improved by passing the makeup feedwater through a demineralizer (paragraph 220-21.74). A demineralizer is illustrated in Figure 220-22-1. The quality of the water entering and exiting the demineralizer is monitored separately by in-line conductivity cells. A comparison test is not required for demineralizer outlet conductivity cell. The makeup feedwater conductivity shall be monitored immediately after placing a feedwater tank on suction. The maximum permissible makeup feedwater conductivity is 15 µmho/cm. If the feedwater exceeds this requirement, a different tank shall be placed on suction. If an emergency exists or if no reserve feedwater is available which meets the 15 µmho/cm limit, the water may still be sent through the demineralizer. This situation may arise when using shore-source condensed steam as feedwater whose conductivity limit is 25 µmho/cm. The demineralizer will improve the quality of this water, but the useful life of the mixed bed ion exchange resin will be shortened. The makeup feedwater conductivity of an operating ship will normally be about 5 to 6 µmho/cm. The maximum permissible demineralized makeup feedwater conductivity is 1.0 µmho/cm. If the demineralized makeup feedwater conductivity exceeds this limit, the resin is expended. The demineralizer shall be bypassed immediately and the resin shall be replaced. Demineralized makeup feedwater conductivity will normally be about 0.2 µmho/cm. Detailed operating and maintenance instructions for demineralizer systems are contained in NAVSEA Technical Manual S9255-AQ-MMO-010. Under chelant treatment, demineralizers, if installed, shall continue to be operated.

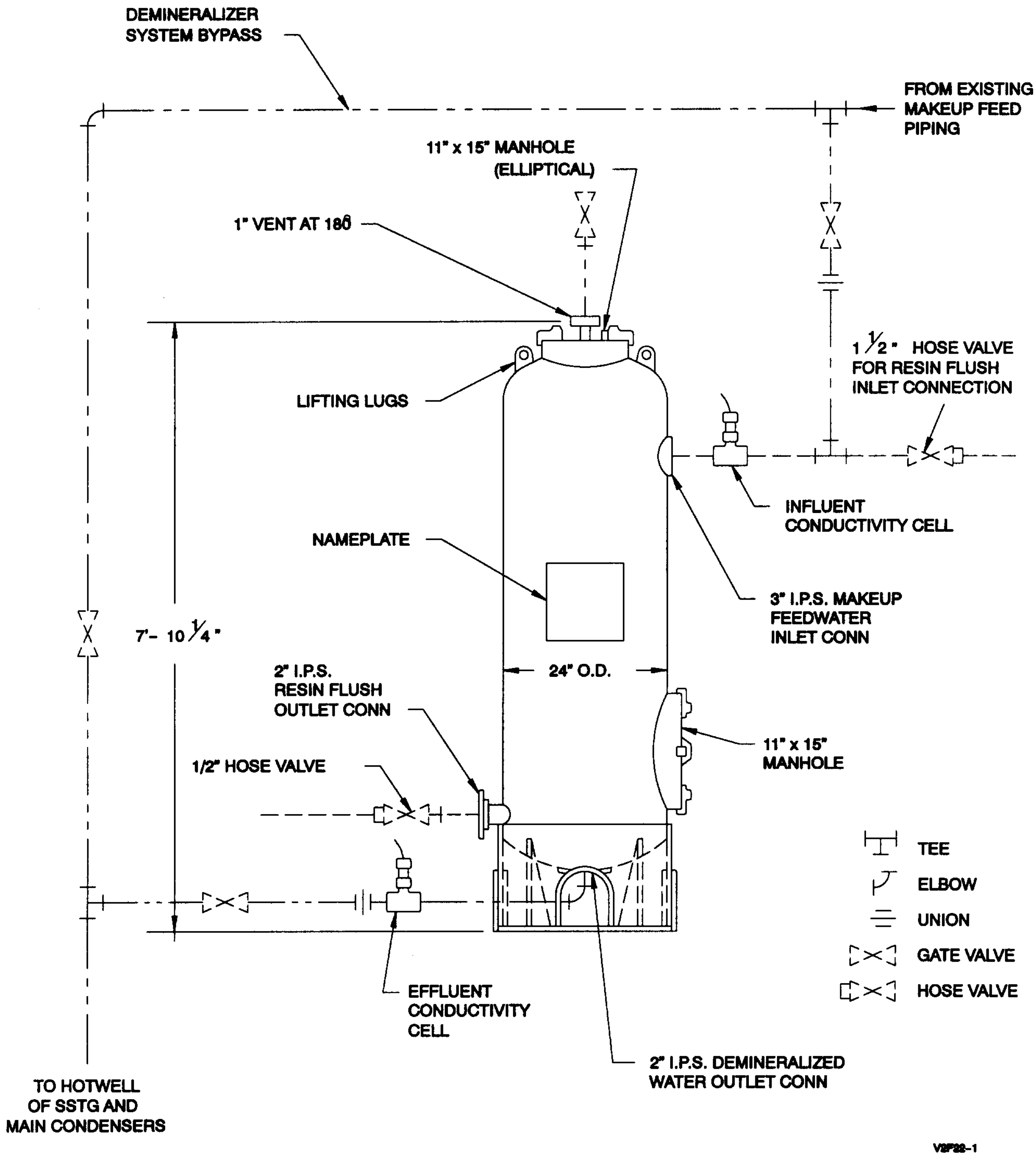


Figure 220-22-1. Ion Exchange Demineralizer System.

220-22.27 CHELANT TREATMENT SYSTEM

220-22.28

The continuous treatment system is prepared for use prior to light off of the first boiler or as soon as good quality condensate is available. The treatment tank holds 30 gallons of treatment solution. The system alarms when the treatment tank level falls to 5 gallons to indicate that preparation of fresh treatment solution will be required shortly. The continuous treatment tank is filled when the 2 gallon alarm sounds. The continuous treatment tank shall be filled within an hour after reaching the 2 gallon level. When the treatment level reaches 2 gallons, a solenoid valve closes, securing flow of treatment to the DFT. The treatment tank is prepared using hydrazine solution, EDTA and either trisodium or disodium phosphate. The amount of EDTA and disodium phosphate required for 600 psig is given in Table 220-22-3. The amount of EDTA and trisodium phosphate required for 600 psig is given in Table 220-22-4. The EDTA and phosphate are added to hot feedwater in the 10-liter safety dispensing bottle and completely dissolved. One gallon of 7% hydrazine solution is added to each tank. The chemicals are added using the enclosed transfer system. The procedure for preparation of the treatment solution is given in Figure 220-22-2. The time of completion of preparation of continuous treatment solution with the amounts of chemicals used is entered on the chelant feedwater log. The continuous treatment tank level is entered daily in the chelant feedwater log.

220-22.29

Hydrazine is an extremely hazardous chemical and all personnel involved in its handling must be aware of the proper handling procedures, including the emergency spill clean up procedures. The use of the enclosed transfer system insures that personnel receive zero exposure to hydrazine solution or vapors. The sealed hydrazine bottle is never to be opened except by using the enclosed transfer system. Proper preparation of the treatment solution will flush the hydrazine bottle with at least 25 gallons of condensate, thereby removing all residual hydrazine and allowing safe handling of the empty bottle for disposal. Treatment flow shall be initiated within 30 minutes of when the first boiler in the space is placed on line and secured within 2 hours after fires are out on the last boiler. The procedure for operation of the injection system is given in Figure 220-22-3.

Table 220-22-3. CHEMICAL WEIGHTS REQUIRED TO PREPARE CONTINUOUS TREATMENT TANK FOR 1200 PSI BOILERS

	EDTA	Disodium Phosphate
Ship	**Ounces**	**Ounces**
CG 16-18, 26-34	45	10
CV 62, 67, FF 1052-1097	55	12
CG 19-24, CV 63, 64, 66	60	13

Table 220-22-4. CHEMICAL WEIGHTS REQUIRED TO PREPARE CONTINUOUS TREATMENT TANK FOR 600 PSI BOILERS

	EDTA	Disodium Phosphate
Ship	**Ounces**	**Ounces**
AOE 1-4, AGF 3, AGF 11, LHA 1-5, LHD 1-5, LPD 1, 4-10, 12-15, LSD 37-40	20	10
AD 37, 38, 41-44, AE 27-29, 32-35, AFS 1-7, AOR 1-7, AS 33, 34, 36, 37, 39-41, LCC 19, 20, LPH 3, 7, 9-12, LSD 36	30	15
AO 177-180, 186, LKA 113-117	60	25

220-22.30

The nitrogen pressure on the mixing tank is adjusted between 20 and 60 psig to achieve proper treatment flow. The required pressure will vary between systems depending on the location of the mixing tank relative to the DFT. For initial system operation, set the mixing tank nitrogen pressure as required to obtain the required treatment flow given in Table 220-22-5 based on the indicated flowrate at the control panel rotameter. If after the first day of steaming, the hydrazine level is above or below limits, decrease or increase the nitrogen pressure in up to 5 psig increments until the hydrazine level remains within limits. The mixing tank pressure that maintains the feedwater hydrazine within limits is the operating pressure for this system. This pressure is used whenever the system is operated. Record the operating pressure in the chelant treatment feedwater chemistry worksheet/log daily. Once the operating pressure is determined, further adjustment should not be necessary. Refer to Table 220-22-6 when hydrazine levels are out of limits. If the hydrazine level is out of limits, corrective action shall be taken and the DFT hydrazine level retested within 4 hours. During normal at sea operations the hydrazine level should not be continually at the upper or lower limits.

220-22.31 STEAMING WITHOUT CONTINUOUS TREATMENT.

A boiler may be steamed when the continuous treatment system is secured for repair. This will require steaming without EDTA or hydrazine. The boiler water limits shall be maintained using batch chemical injection, paragraph 220-22.45. Continuous blowdown shall be secured while the treatment system is secured. If the continuous treatment system cannot be repaired within 168 steaming hours, notify the Type Commander and send an information copy to ISIC, NAVSEA, and NSWCCD-SSES. If a boiler is steamed without continuous treatment for more than 168 hours since the last waterside inspection, there shall be an inspection at the next availability or within 2,000 steaming hours of the last inspection. The boiler may be steamed for less than 24 hours without continuous treatment to minimize disposal of chemicals. For instance, when a fresh tank of treatment solution is required within 24 hours of securing and the full tank would have to be dumped for hydrazine layup.

PREPARATION OF CONTINUOUS TREATMENT SOLUTION

WARNING

Wear a face shield when mixing treatment chemicals. Test shower/eyewash prior to adding chemicals to insure cool water is available for emergencies. If chemicals contact skin, flush or show with cool water. If chemicals enter the eyes, flush with cool water for 15 minutes, raising and lowering eyelids. See immediate medical attention.

1. Verify that the following valves are closed: 5, 14, 15, 16, 20, 21, 22, 23 and 24 (Figure 220–21–6).
2. Open valves 9 and 11. Ensure valves 10, 12 and 13 are open and energize sight flow lights. Verify 0 psig pressure on mixing tank and piercing apparatus.
3. Open valves 6, 7 and 8.
4. Drain mixing tank by opening valves 15 and 16. After draining close valves 15 and 16.
5. Add 1 gallon of condensate to mixing tank by shutting valve 6 and opening valve 5. Secure valve 5 when the tank level reaches 1 gallon.
6. Retract cutter fully by rotating handwheel counterclockwise and remove piercing apparatus cap. Remove empty hydrazine bottle.
7. Check cap o-ring and replace if damaged.

WARNING

Wear face shield, goggles, overalls, apron, and gloves when preparing continuous treatment solution. If leakage develops, put on boots before repairs are accomplished.

8. Pour the previously dissolved solution of EDTA and sodium phosphate into the piercing apparatus. Allow to drain into mixing tank.
9. Carefully insert sealed hydrazine bottle into piercing apparatus, replace cap and tighten until fully closed.
10. Puncture hydrazine bottle by rotating handwheel fully clockwise. Open valve 6 and observe sight flow to determine when addition is complete.

WARNING

The feedwater used to prepare the treatment solution must be less than 200°F to prevent melting the hydrazine bottle. Once the hydrazine bottle is punctured, do not open the piercing apparatus until completion of flushing.

11. After hydrazine addition is complete, secure valves 7 and 9.
12. Commence bottle flush. Open condensate flush valve 5. Ensure valves 6, 8 and 11 are open.
13. Continue flush until tank is filled to 28 gallon mark, then secure valve 5. Do not over fill.
14. Open valves 7 and 9 to drain piercing apparatus. Use sight flows to determine when draining is complete.
15. Secure valves 6, 7, 8, 9, 11 and 13.
16. Open nitrogen bottle valve and set nitrogen pressure. Open valve 23 to mix solution and pressurize tank.
17. After tank is pressurized, close valve 23 and open valve 13.
18. Turn off sight flow lights.

NOTE

1. Hydrazine bottles must not be used for any other purpose.
2. Mixing tank must be drained prior to preparing fresh treatment.
3. A sharpened, arrowhead style cutter must be installed in the bottom of the piercing apparatus. The upper cutter may be shaped or sharpened.

Figure 220-22-2. Preparation of Continuous Treatment Solution.

STARTING INJECTION OF CONTINUOUS TREATMENT

1. Verify that the following valves are closed: 4, 5, 6, 7, 8, 9, 11, 14, 16, 20, 21 and 22 (Figure 22–21–6).

2. Ensure that the following valves are open: 1, 3, 12, and 13. Turn on power to system and set alarms to normal. Check alignment of control air and feed flow transmitter signals.

3. Open nitrogen bottle valve and set nitrogen pressure. Open valve 24.

4. Open valve 15 and then valves 21 and 22.

5. Verify flow on rotameter.

NOTE

1. System will automatically be secure when tank level reaches 2 gallons.

2. If the control valve fails, the treatment system can be manually operated by securing valve 1, then open valve 4 and adjust flow in accordance with Table 220–22–5.

3. Open valve 4 momentarily to remove bubbles from rotameter tube as required.

SECURING

1. Close DFT cutout valves 21 and 22.

2. Secure valve 15.

3. Secure nitrogen valve 24 and nitrogen bottle valve.

4. Set alarms to off and secure power.

Figure 220-22-3. Operation of Continuous Treatment Solution.

Table 220-22-5. APPROXIMATE CHELANT BOILER FEEDWATER TREATMENT FLOW

		Approximate Chelant Treatment Flow Per Boiler (Rotameter Reading)											
		Percent Boiler Load											
Ship	**Float***	**10**	**20**	**30**	**40**	**50**	**60**	**70**	**80**	**90**	**100**	**110**	**120**
AD 37,	A	1	1.5	2	2.5	2.5	3	3	3.5	4	4	4	4.5
38, 41-44	A	1	1.5	2	2	2.5	3	3	3	3.5	3.5	4	4
AE 27-29,	A	1	1.5	2	2	2.5	3	3	3	3.5	3.5	4	4
32-35	P	1.5	2.5	3	3.5	4	4.5	4.5	5	5.5	5.5	6	6
AFS 1-7													
AGF 3,													
11													

Table 220-22-5. APPROXIMATE CHELANT BOILER FEEDWATER TREATMENT FLOW - Continued

Ship	Float*	Approximate Chelant Treatment Flow Per Boiler (Rotameter Reading)											
		Percent Boiler Load											
		10	**20**	**30**	**40**	**50**	**60**	**70**	**80**	**90**	**100**	**110**	**120**
AO 177-180, 186 AOE 1-4 AOR 1-7 AS 33-41	A J J A	1 1 0.5 1	1.5 1.5 1 1.5	2 2 1.5 2	2 2.5 1.5 2	2.5 2.5 2 2.5	3 3 2 3	3 3 2 3	3.5 3.5 2.5 3.5	3.5 3.5 2.5 4	4 4 3 4	4 4 3 4	4 4.5 3 4.5
CG 16-34 CV 62-64, 66, 67 FF 1052-1097	J J A	1 1 1	1.5 2 2	1.5 2.5 2.5	2 3 3	2.5 3 3	2.5 3.5 3.5	3 4 4	3 4 4	3.5 4.5 4.5	3.5 4.5 4.5	3.5 5 5	4 5.5 5
LCC 19, 20 LHA 1-5 LHD 1-5 LKA 113-117	A A A A	1 2 2 1	1.5 3 3 1.5	2 4 4 2	2.5 4.5 4.5 2	2.5 5 5 2.5	3 5.5 5.5 3	3 6 6 3	3.5 7 7 3	4 7.5 7.5 3.5	4 8 8 3.5	4 8.5 8.5 4	4.5 9 9 4
LPD 1, 4-10, 12-15 LPH 3, 7, 9-12 LSD 36-40	P A P	1.5 1 1.5	2.5 1.5 2.5	3 2 3	3.5 2.5 3.5	4 2.5 4	4.5 3 4.5	4.5 3 4.5	5 3.5 5	5.5 4 5.5	5.5 4 5.5	6 4 6	6 4.5 6

* FloatsP - black glass
A - sapphire (red)
J - stainless steel
Rotator tube: 1/8-20-G-5

Table 220-22-6. TROUBLESHOOTING CONTINUOUS TREATMENT SYSTEM

Cause	Corrective Action
1. **Feedwater hydrazine below 10 ppb.**	
a. Improper stem alignment.	a. Check treatment flow rate. Verify proper system alignment
b. Mixing tank pressure below system operating pressure.	b. Check mixing tank pressure. Verify nitrogen cylinder has pressure, valve 24 is open, and regulator is set to system operating pressure.

Table 220-22-6. TROUBLESHOOTING CONTINUOUS TREATMENT SYSTEM - Continued

Cause	Corrective Action
c. Control system malfunction.	c. Ensure control air and feed flow transmitter (FFXMTR) signals are aligned.
	(1) Ensure FFXMTR signals are correct for boiler load, including secured boilers. Repair/calibrate FFXMTR.
	(2) Ensure that signal in cabinet equals that at FFXMTR. If cabinet pressure is lower, locate and repair leaks.
	(3) Ensure control air is set to 20 psi.
	(4) Verify reducing relays and meter control valve are operating properly; calibrate if required.
d. Solenoid valve closed.	d. Check electrical power/repair solenoid valve. *
e. Strainer clogged.	e. Repair strainer. *
f. Tank level low.	f. Prepare continuous treatment.
g. Excessive DFT pressure.	g. Correct DFT operation
h. DFT sampling system leakage.	h. Repair DFT sampling system.
i. High DFT dissolved oxygen	i. Check DFT operation; repair DFT.
j. Sampling during change in load.	j. Resample under steady load.
k. Treatment system leakage	k. Check for dried chemicals at control cabinet fittings, DFT flanges, line connections, and valves. Repair leak. *
l. Rotamotor float struck.	l. Increase nitrogen pressure and open bypass valve (4) briefly to force float free. If float remains stuck, carefully remove rotameter tube and push float free. Center spring in bottom of tube and replace rotameter tube. *
2. **Feedwater hydrazine above 40 ppb.**	
a. Improper system alignment.	a. Check treatment float rate. Ensure bypass valves 4 and 21 are closed.
b. Light off of boiler under hydrazine lay up.	b. Allow excess hydrazine to deplete with normal steaming check
c. Malfunctioning control system	c. Check control system (see above).
d. Sampling during change in load.	d. Resample under steady load.
e. Mixing tank pressure above system operating pressure.	e. Reduce nitrogen regulator adjustment, bleed pressure from mixing tank using vent, reset system operating pressure.
f. Rotamotor float struck.	f. Increase nitrogen pressure and open bypass valve (4) briefly to force float free. If float remains stuck, carefully remove rotameter tube and push float free. Center spring in bottom of tube and replace rotameter tube. *

*WARNING: The treatment solution is hazardous; avoid contact with skin or eyes. Relieve system pressure and wear safety equipment when making repairs to solenoid valve, strainer, rotameter, or other system components. See paragraph 220-25.11 for safety procedures. See 220-25.16 to correct treatment leakage.

220-22.32 REQUIREMENTS FOR CHELANT TREATMENT OF PROPULSION BOILER WATER

220-22.33

Boiler water conditions under chelant treatment are controlled by maintaining alkalinity, phosphate, conductivity and chloride within specified limits. The boiler water control limits for chelant treatment are the same for all propulsion boilers.

220-22.34

Normal control of the boiler water limits is through the continuous treatment system. Continuous injection of trisodium EDTA and trisodium or disodium phosphate into the DFT, together with continuous blowdown, will result in the alkalinity and phosphate being within limits when good quality feedwater is used. Continuous blowdown system will also maintain boiler water chloride level within limits under normal conditions. Conductivity reflects the other boiler water parameters and will be within limits when alkalinity, phosphate and chloride are within limits and unusual contamination is not occurring.

220-22.35

Injection of treatment chemicals using the batch treatment system is primarily required for freshly filling the boiler and when chemical casualties occur. Three chemicals are used to adjust the boiler water parameters; trisodium phosphate, disodium phosphate and caustic soda. Trisodium phosphates raises both alkalinity and phosphate. Disodium phosphate increases phosphate level without significantly affecting alkalinity. Caustic soda raises alkalinity only. EDTA and hydrazine are never added through the batch treatment system.

220-22.36

The paramount aim of boiler water treatment using chelant treatment is to maintain boiler water within limits. This accomplished by properly maintaining the continuous treatment feed rate and proper adjustment of the continuous blowdown rate. A log of boiler water results shall be maintained in accordance with paragraph 220-27.42.

220-22.37 INITIAL TREATMENT.

It is good engineering practice to use the hottest feedwater available to fill a boiler in preparation for light-off; however, the following waters are acceptable when freshly filling:

1. Hot deaerated feedwater.
2. Cold feedwater, meeting the requirements of paragraph 220-22.22 if the feedwater is from a shore source, or paragraph 220-22.11 if from the ship's evaporators. Cold feedwater should not be used unless a ship is unable to operate the DFT.
3. Hydrazine/morpholine treated feedwater used for layup.

220-22.38

The following waters may not be used to fill a boiler in preparation for light-off:

1. Raw shore water.
2. Water used to hydrostatically test a boiler after an acid cleaning and any other water that contains sodium nitrite.
3. Feedwater that does not meet the requirements of paragraph 220-22.22 for shore source feedwater or paragraph 220-22.11 for reserve feedwater from the ship's evaporates.

220-22.39

All the waters listed in paragraph 220-22.38 shall be dumped. Flushing of the watersides, steamsides, or feed tanks that contained the water is required. If sodium nitrite was not properly dissolved in the water or drained from the boiler, it can cause boiler water control problems.

220-22.40

The boiler is normally filled to the bottom of the direct reading gauge glass with deaerated feedwater (if available). Feedwater, used in a hydrostatic test, or hydrazine/morpholine treated feed water used for layup, must be drained to the bottom of the direct reading gauge glass. Trisodium phosphate is added using the batch chemical treatment system to bring alkalinity to 0.250 epm and phosphate to 25 ppm. The chemical is prepared as follows:

WARNING

Wear a face shield when dissolving trisodium phosphate. Concentrated trisodium phosphate solutions are corrosive and cause burns to skin, eyes, and body tissues. Affected personnel shall flush skin with cold water. If trisodium phosphate or its solutions enter the eyes, flush with cold water for 15 minutes and obtain immediate medical attention.

1. Locate the boiler water volume for chemical treatment, in gallons, from Table 220-22-7.
2. Locate the weight of trisodium phosphate, in ounces, from Table 220-22-8.
3. Half fill the 10-liter safety dispensing bottle with feedwater at 50°C (122°F) or less.
4. Weigh the necessary amount of chemical and transfer to the 10-liter safety dispensing bottle. (See notes below.)
5. Add feedwater to the shoulder of the bottle, cap the bottle and spout, then shake to dissolve.

Table 220-22-7. BOILER WATER VOLUME FOR CHEMICAL TREATMENT OF PROPULSION BOILERS

Boiler Water Volume (Gallons)	Ships
1,000	CG 16-18, 26-34, FF 1052-1097
1,200	AGF 3, LPD 1, 2, 4-6
1,300	AGF 11, CG 19-24, LPD 7-10, 12-15, LSD 37-40
1,400	AS 36, LCC 19
1,500	AD 37, 38, 41-44, AE 27-29, AFS 1-3, AS 33, 34, 39-41
1,600	AFS 4-7, LPH 3, 7, 9-12, LCC 20, LSD 36
1,700	AE 32-35, AS 37, AOR 1-7
1,900	AOE 1-3, CV 62
2,000	CV 67
2,200	CV 63, 64, 66
2,300	AOE 4

Table 220-22-7. BOILER WATER VOLUME FOR CHEMICAL

TREATMENT OF PROPULSION BOILERS - Continued

Boiler Water Volume (Gallons)	Ships
2,900	LKA 113-117, AO 177-180, 186
3,100	LHA 1-5, LHD 1-5

Table 220-22-8. TRISODIUM PHOSPHATE DOSAGE FOR FRESHLY FILLING CHELANT TREATMENT PROPULSION BOILERS

Boiler Water Volume for Chemical Treatment (Gallons)	Weight of Trisodium Phosphate Required for Initial Treatment (Ounces)
1,000	12
1,200	15
1,300	16
1,400	17
1,500	19
1,600	20
1,700	21
1,900	24
2,000	25
2,200	28
2,300	29
2,900	36
3,100	39

NOTE

The safety dispensing bottle shall be marked and used for boiler treatment chemicals only.

NOTE

As the trisodium and disodium phosphate dissolve they generate heat, so water temperature will increase slightly. Do not use very hot water to dissolve the chemicals because the safety dispensing bottle is made from linear polyethylene which has a maximum use temperature of 80°C (176°F). Trisodium phosphate can be added to water or vice versa without difficulty.

NOTE

The solubility of trisodium phosphate is about 5 pounds per 10 liters of water at 50°C (122°F).

220-22.41

All propulsion boilers are equipped with a batch chemical injection system. The injection procedure, including a schematic of the system, is shown in Figure 220-22-4. When an injection system is used, care must be exercised to keep the amount of air introduced into the boiler to a minimum. The tank is overfilled slightly to bleed air out of it. Overfilling must be minimized to avoid the loss of treatment chemicals. In addition, the tank must be on-line for a least 10 minutes to ensure that all of the treatment is flushed into the boiler. Check boiler water level to verify that chemicals are added to the boiler. It is permissible to inject chemicals at any time during the boiler filling process. On some ships it may be preferable to add the chemicals before filling the boiler, particularly if low test results for phosphate or alkalinity have been previously encountered in the after-on-line sample. Upon completion of chemical addition, finish filling the boiler to the light-off level or, if the boiler has been overfilled, drain until the proper water level is reached. A boiler water sample, obtained from a freshly filled, chemically treated boiler prior to light-off, is not required because the sample is not representative and is therefore meaningless. Circulation of boiler water to distribute the chemicals is prohibited because boiler metal damage through oxygen attack may result. The freshly filled and treated boiler should be lit off immediately, but not later than 24 hours after being filled. Preferably, the boiler should not be filled unless it is expected that it will be off within 24 hours. If the boiler cannot be lit off within 24 hours after filling, it shall be dumped and placed under layup. A boiler is considered to be steaming (on-line) for boiler water chemistry purposes from the time auxiliary or main steam stops are open until fires are secured. For calculation of steaming hours, a boiler is considered to be steaming when the fires are lit.

NOTE

Figure 220-22-4 is based on NAVSEA STD DWG 803-1385375. Ships that do not have the configuration specified in this figure/drawing are being upgraded by ship alteration. Figure 220-22-4 may be marked up to reflect individual ship configurations and used for chemical injection until the applicable ship alteration has been accomplished.

220-22.42 STEAMING BOILERS.

Boiler water conditions in a steaming boiler, using chelant treatment, shall be maintained in accordance with the following:

Boiler Water

Constituent or Property	Requirement
Alkalinity	0.100 to 1.000 epm
Phosphate	10 to 40 ppm
Conductivity	500 µmho/cm maximum
Chloride	1.0 epm maximum

220-22.43

Boiler water conditions are determined by obtaining a boiler water sample and testing for alkalinity and phosphate (paragraph 220-26.28), conductivity (paragraph 220-26.30), and chloride (paragraph 220-26.31). Boiler water samples shall be obtained from a steaming boiler in accordance with the following requirements:

1. Within 1/2 hour after the boiler is placed on-line (auxiliary or main steam stop open).
2. As often as required to maintain limits but at least every 24 hours (maximum of 24 hours between samples). If the continuous boiler water conductivity indicating system is not operational, the maximum time between samples is reduced to every 8 hours.
3. Within 1 hour prior to surface or bottom blowdown.

4. 30 to 45 minutes after surface or bottom blowdowns are completed.

5. 60 to 90 minutes after batch chemical treatment.

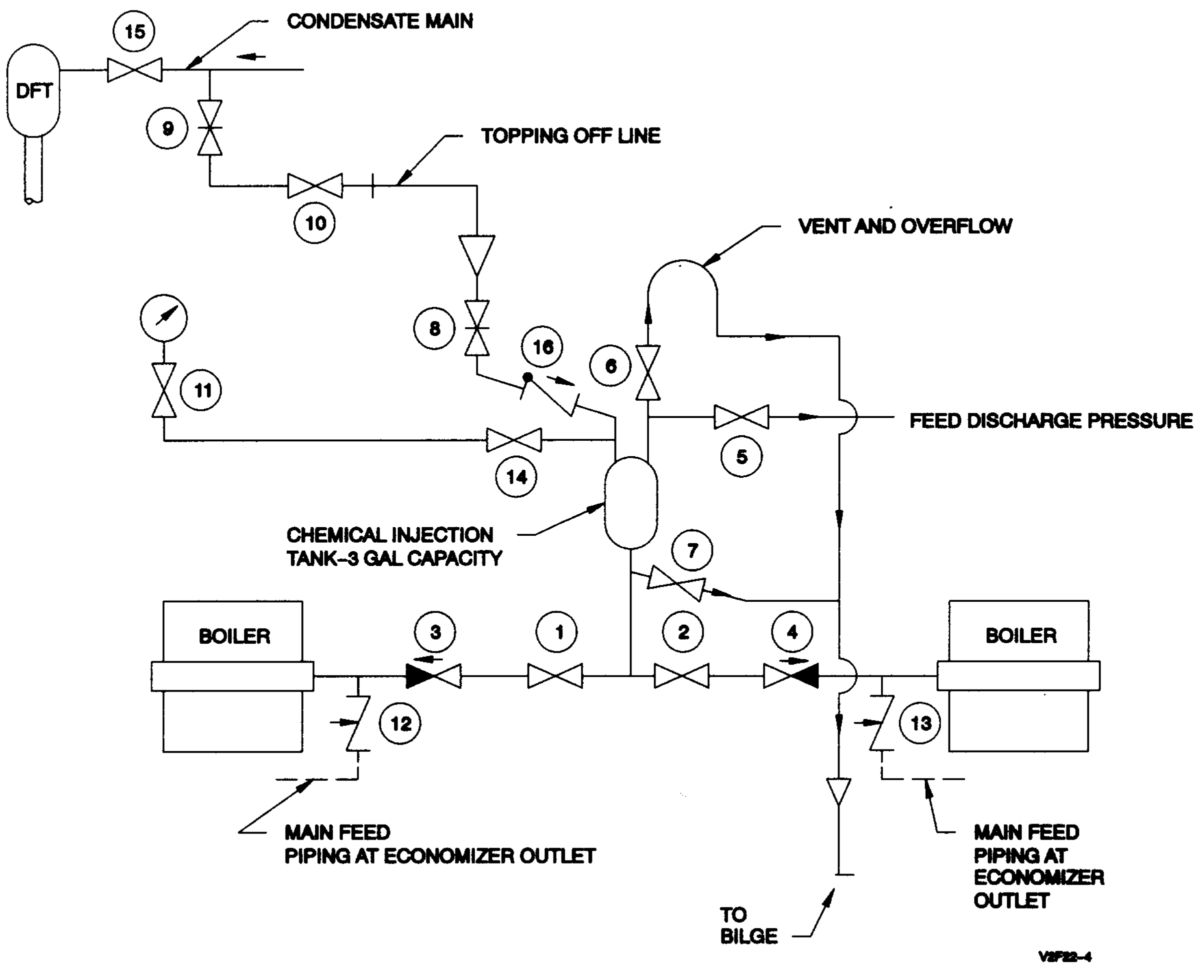
6. Within 90 minutes prior to securing the boiler.

220-22.44

The above sampling frequencies apply to normal boiler water conditions. Under casualty control circumstances rapid response is needed in order to prevent boiler damage. When a boiler is secured as a result of a non-chemistry related casualty, control of the casualty takes precedence over the requirements of paragraph 220-22.43. In these cases, the prior to securing sample is not required. The sampling requirements during casualty control drills are the same as those for the actual casualty. It is recommended that affected boilers be tested before initiating the drill session to ensure boiler water is not contaminated. The salinity indicators are continuously monitored during the drill for signs of contamination. Boiler samples are required regardless of how long the drill continues. If an actual chemistry casualty occurs during the drill, terminate the drill and control the chemistry casualty.

220-22.45 Alkalinity and Phosphate.

Under normal operations alkalinity and phosphate will be controlled by the continuous treatment system and continuous blowdown. Batch chemical treatment should not be required except for freshly filling, occasionally when coming on the line following wet layup, or due to contamination. Batch treatment is required when alkalinity or phosphate is below the lower limits and to prevent alkalinity and phosphate from going below the lower limit such as prior to surface blowdown. When boiler water sample results indicate that batch treatment is required, the injection shall be initiated within 1 hour after sampling. Due to the wider range of alkalinity and phosphate, adjustment can be accomplished using a single treatment chemical. Trisodium phosphate is added when alkalinity and phosphate are required. Disodium phosphate is added when only phosphate is required and caustic soda is added when only alkalinity is required. Caustic soda is required as a normal treatment chemical and does not require the Engineer Officer’s permission for injection. These chemicals, especially caustic soda, are hazardous. Personnel must be familiar with the safety and handling procedures in Section 25. The procedure for batch chemical injection is as follows:



WARNING

PERMANENT TAG "DO NOT OPEN WHEN TANK IS UNDER PRESSURE."

Key:

1. **Line Stop Valve**
2. **Line Stop Valve**
3. **Stop Check Valve**
4. **Stop Check Valve**
5. **Injection Tank Pressurizing Line Valve (From Feed Discharge Header)**
6. **Tank Vent and Overflow Valve**
7. **Tank Drain Valve**
8. **Funnel Fill Valve**
9. **Condensate Root Valve**
10. **Topping Off Line Valve**
11. **Gauge Valve (Normally Open)**
12. **Main Feed Check Valve**
13. **Main Feed Check Valve**
14. **Pressure Gauge Root Valve (Normally Open)**
15. **Condensate Inlet Valve To DFT**
16. **Fill Line Check–Not Required Unless Installed By SHIPALT**

Figure 220-22-4 Propulsion Boiler Chemical Injection Procedure (Sheet 1 of 2).

WARNING

WEAR PROTECTIVE CLOTHING WHILE POURING CONCENTRATED CHEMICALS INTO CHEMICAL INJECTION TANK AND WHILE TOPPING OFF.

1. Ensure injection pressure line valve 5, stop valves 1 and 2, and stop check valves 3 and 4 are closed.

2. Check pressure gauge for zero pressure.

3. Ensure injection tank is empty by first slowly opening vent valve 6 and then drain valve 7.

4. Close drain valve 7 when tank is empty.

5. Open funnel fill valve 8.

6. Pour boiler treatment chemicals (in solution) into the chemical injection tank through the funnel fill connection.

7. Top off injection tank. To ensure no air is present in the tank, add water via the topping off line valves 9 and 10 until overflow just starts. For cold plant startup when condensate is not available, top off tank with reserve feed.

8. Close valves 10, 8, 9 and 6.

9. Slowly open valves 3 and 1, or 4 and 2, depending on which boiler is to be injected.

10. Slowly open valve 5. Observe tank pressurization.

11. Maintain chemical injection for 10 minutes to flush out chemical injection system.

12. Close valves 5, 1 and 3, or 5, 2 and 4 depending on which boiler was injected.

13. Drain chemical injection by first slowly opening vent valve 6 and then opening drain valve 7.

14. Close drain valve 7 and vent valve 6 when all pressure has been relieved and the tank is empty.

Figure 220-22-4 Propulsion Boiler Chemical Injection Procedure (Sheet 2 of 2).

WARNING

Wear a face shield when mixing treatment chemicals and when treating the boiler. Additionally, goggles, rubber or plastic gloves and an apron shall be worn when handling caustic soda. Caustic soda and trisodium phosphate are corrosive and cause burns to skin, eyes and body tissues. If treatment chemicals or their solutions enter the eyes, flush with cold water for 15 minutes lifting the upper and lower eye lids alternately and obtain immediate medical attention.

1. Determine the alkalinity and phosphate concentrations in the boiler water from the sample results.
2. Locate the column for the boiler water alkalinity across the top of Table 220-22-9.
3. Within the alkalinity column, locate the sub-column for the boiler water phosphate.
4. Read down the sub-column to find the required chemical and the weight of the chemical for the appropriate boiler water volume.
5. Weigh the chemical to the nearest half ounce, dissolve in feedwater in the 10-liter safety dispensing bottle, and inject the solution into the boiler in accordance with paragraphs 220-22.40 and 220-22.41.

NOTE

Large quantities of disodium phosphate should be added to water because disodium phosphate tends to cake if water is poured over it.

Table 220-22-10 shows examples of batch chemical treatment calculations.

220-22.46

Alkalinity and phosphate levels in boiler water will increase after light off until a balance is reached between the incoming chemicals from the continuous treatment system and the loss of chemicals via continuous blowdown. This level will vary depending on boiler load, makeup rate and quality of feedwater. The upper limits allow room for the increase in chemical level. The trisodium phosphate dosage will bring the alkalinity to between 0.200 and 0.300 epm and the phosphate to over 20 ppm. The caustic soda dosage will increase the alkalinity to between 0.200 and 0.300 epm. The disodium phosphate dosage will raise the phosphate to 25 to 30 ppm.

220-22.47

If alkalinity or phosphate is above the upper limits, the boiler must be surface blown to reduce the alkalinity or phosphate. If alkalinity or phosphate is below the lower limits, regardless of conductivity or chloride, the boiler must be treated prior to surface blowdown except in response to a high water casualty. A 10 percent blowdown will cause the alkalinity, phosphate, chloride and conductivity to decrease by 10 percent. If the phosphate exceeds 100 ppm, more feedwater will be used for blowdown than for securing and dumping in lowering phosphate to levels that are within limits. If the alkalinity exceeds 2.0 epm, the boiler must be secured to stop caustic corrosion unless the Commanding Officer directs continued steaming. If the Commanding Officer directs continued steaming, the steaming rate should be minimized to reduce boiler carryover.

220-22.48 Conductivity.

Conductivity of the boiler water is a measure of the total dissolved solids present in the boiler water from both treatment chemicals and contaminants. Conductivity will be below the upper limit as long as alkalinity, phosphate and chloride are within limits and unusual contamination is not occurring. Under normal conditions, boiler water conductivity will be controlled by continuous blowdown. High levels of conductivity are reduced by surface blowdown. When the conductivity reached 1,200 µmho/cm, more feedwater is used for blowdown that for securing and dumping in lowering conductivity to levels that are within limits. If boiler water conductivity exceeds 2,000 µmho/cm for nay reason, the boiler must be secured to stop carryover deposits in the superheater unless the Commanding Officer directs continued steaming. If the Commanding Officer directs continued steaming, the steaming rate should be minimized to reduce boiler carry over. The superheater must be flushed and inspected following an incident where boiler water conductivity exceeds 2000 µmho/cm.

Table 220-22-9. BATCH CHEMICAL DOSAGE FOR CHELANT TREATMENT

Boiler Water Alkalinity (epm)	**0**		**0.025 to 0.075**		**0.100 to 0.150**		**more than 0.150**	
Boiler Water Phosphate (ppm)	**0 to 15**	**more than 15**	**0 to 15**	**more than 15**	**0 to 15**	**more than 15**	**less than 10**	**10 to 15**
Required Chemical, ounces								
Boiler Water Volume for Chemical Treatment (Gallons)	**TSP**	**CS**	**TSP**	**CS**	**TSP**	**CS**	**DSP**	**DSP**
1,000	15	1.5	10	1	7.5	1	5	3
1,200	18	2	12	1.5	9	1	6	2.5
1,300	19.5	2	13	1.5	10	1	6.5	4
1,400	21	2	14	1.5	10.5	1	7	4
1,500	22.5	2.5	15	1.5	11.5	1	7.5	4.5
1,600	24	2.5	16	1.5	12	1.5	8	4.5
1,700	25.5	2.5	17	2	13	1.5	8.5	5
1,900	29	3	19	2	14.5	1.5	9.5	5.5
2,000	30.5	3	20	2	15	1.5	10	6
2,200	33.5	3.5	22	2.5	16.5	2	11	6.5
2,300	35	3.5	23	2.5	17.5	2	11.5	7
2,900	44	4.5	29.5	3.5	22	2.5	14	8.5
3,100	47	5	31.5	3.5	23.5	2.5	15	9
TSP = Trisodium Phosphate CS = Caustic Soda DSP = Disodium Phosphate								

Table 220-22-10. EXAMPLES OF CHELANT BATCH DOSAGE

Boiler Water Results		**Boiler Water Volume for Chemical Treatment (Gallons)**	**Required Chemical**	**Ounces of Chemical**
Alkalinity (emp)	**Phosphate (ppm)**			
0.050	10	1,000	TSP	10
0.050	30	1,700	CS	2
0.825	5	2,000	DSP	10
0.000	0	1,300	TSP	19.5
TSP = Trisodium Phosphate CS = Caustic Soda DSP = Disodium Phosphate				

220-22.49 Theoretical Conductivity.

Theoretical conductivity is calculated daily for a steaming boiler. Theoretical boiler water conductivity can be calculated by combining the contributions from alkalinity, phosphate and chloride. This can be determined by multiplying the alkalinity by 248, the phosphate by 2.25 and the chloride by 145 and adding them together. Normally encountered levels of EDTA and hydrazine do not contribute significantly to the conductivity. Under normal conditions the measured conductivity will not differ from the theoretical conductivity by more than 30 percent. A difference greater than 30 percent may indicate contamination from other than a seawater source, a faulty meter or one or more tests being in error. If measured conductivity differs from theoretical conductivity by more than 30% for the first samples taken following hydrazine/morpholine layup, take no action unless the condition is still present after 24 hours of steaming. If measured conductivity differs from theoretical conductivity by more than 30% for a routine sample:

a. Resample and test to verify results and correct analysis methods.

b. If the second analysis indicates more than a 30% difference between measured and theoretical conductivity, conduct standardization and calibration procedures on all equipment and reagent. Resample and test.

c. If the third analysis indicates more than a 30% difference between measured and theoretical conductivity, contamination other than a seawater source is occurring. The most probable contamination sources are shore water, demineralizer resin and morpholine. If the source of contamination cannot be identified, assistance can be requested from the NSWCCD-SSES.

Boiler water in a steaming boiler shall be maintained in accordance with the requirements for that particular type of boiler. Boiler water samples shall be obtained from a steaming boiler in accordance with the following requirements:

220-22.50 Chloride.

The continuous blowdown system will control boiler water chloride level below the 1.00 epm limit if feedwater quality is properly maintained. Leakage of seawater into the feedwater system or abnormally high makeup rates will cause a continuous increase in the boiler water chloride level. High levels of boiler water chloride are controlled by surface blowdown. If the chloride level reaches 2.50 epm, more feedwater will be used for blowdown than for securing and dumping to bring chloride within limit.

220-22.51 SURFACE BLOWDOWN.

Surface blowdown provides the normal control of boiler water chloride conductivity, chemical overtreatment, and nondetergent lubricating oil. In following the procedures of paragraph 220-22.52, an approximate 5-percent surface blowdown will be obtained; however, there is no requirement for a percentage surface blowdown. Surface blowdown shall be performed on a steaming boiler as necessary to maintain boiler water within limits. It is required that the percentage blowdown be recorded in the chelant boiler water treatment log since it gives an indication of procedural or water treatment problems. When a secured boiler under a steam blanket wet layup is run down to reduce water level, no testing prior to or after the rundown is required; however, the action should be noted on the boiler water log.

220-22.52 SURFACE BLOWDOWN PROCEDURE.

When conducting a surface blow on a steaming boiler, do not permit steam drum water level to drop below the surface blow takeoff or drop out of sight in the boiler water gauge. Do not permit superheater outlet temperature to rise above the maximum limit. Maintain a steady feedwater rate and do not change this rate during blowdown. Ensure that the boiler gravity drain hose valve connection is closed and capped during blowdown (See Figure 220-22-5 for a typical arrangement). Blowdown piping materials are specified in NSTM Chapter 221. Surface blowdown is conducted in the following manner:

1. Obtain permission to conduct blowdown.
2. Prepare the blowdown system by first opening the overboard discharge valve(s) and then the guarding valve(s).
3. By manual or remote manual feedwater control, establish the boiler water level at 3 inches above the surface blow take-off pipe.
4. Wait 4 to 5 minutes and then open the surface blow valve. Do not throttle. Maintain continuous observation of the boiler water level during blowdown.
5. Close the surface blow valve quickly when the water level in the steam drum drops to the surface blow pipe.

6. Repeat steps 3 through 5 as required to correct observed conditions.

7. After completing the surface blow, return water level to normal, close the guarding valve(s) and the overboard discharge valve(s), in that order. Open the drain valve to the bilge to ensure tight seating of the surface blow valve. Close the valve when pressure is relieved. Monel-type guarding and overboard discharge valves require a second securing; therefore, retorque the valves 15 minutes after the boiler blow is completed and the system is secured. The 15-minutes cool down period and retorque of monel valves are required to prevent leakage.

220-22.53 Percent Blowdown.

The percent surface blowdown is determined by using the formula. Round to the nearest whole number (i.e., 10.4% rounds to 10%, 10.5% rounds to 11%).

$$\%\ \text{blowdown} = \frac{100(C_B - C_A)}{C_B}$$

where: C_B = conductivity before blowdown
C_A = conductivity after blowdown

NOTE

The percent of bottom or scum blowdown does not need to be calculated.

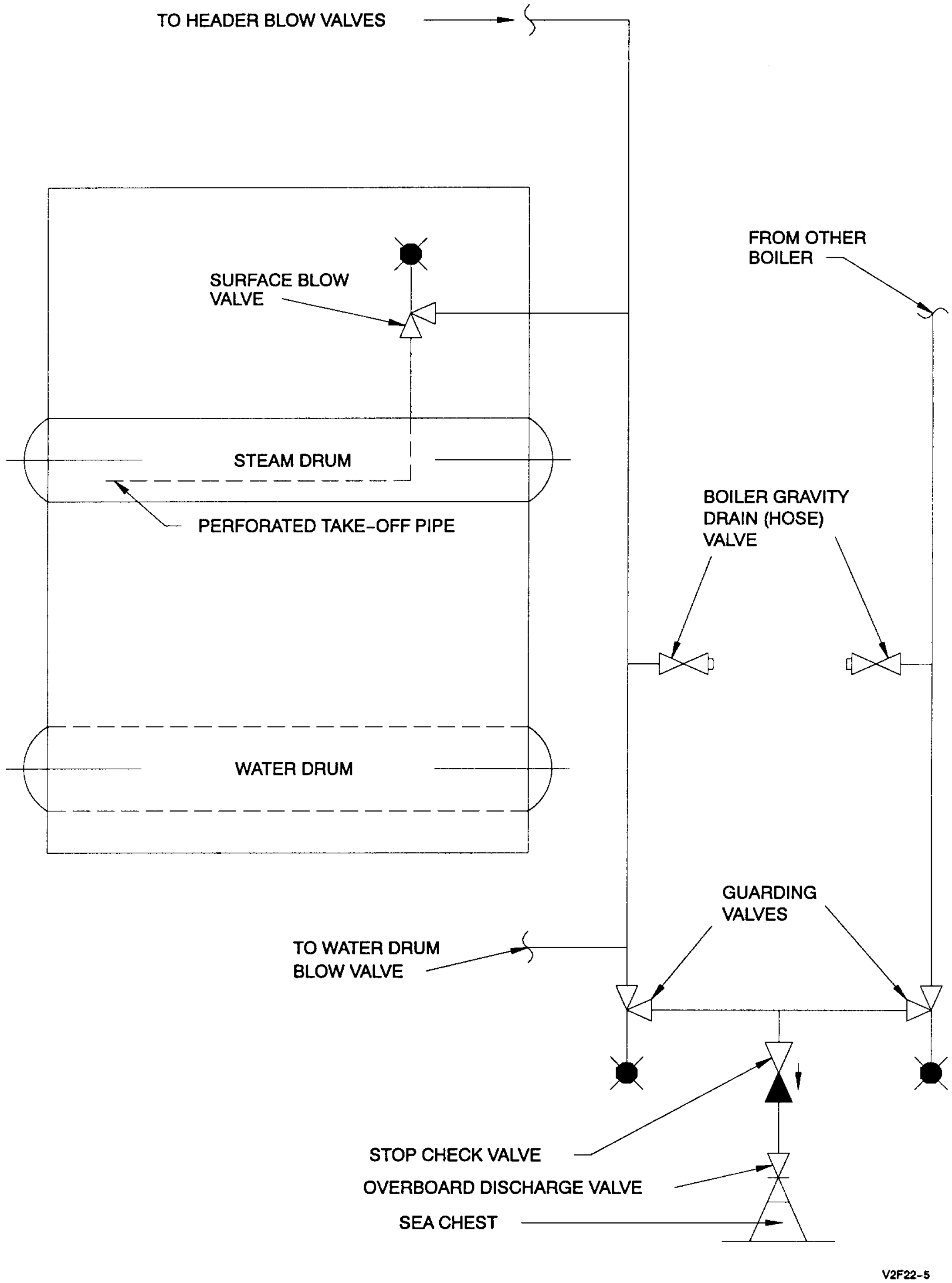


Figure 220-22-5. Boiler Surface Blow Piping, Typical Arrangement.

220-22.54 SCUM BLOWDOWN.

Surface blowdowns are required less frequently under chelant treatment due to the use of the continuous blowdown. In order to prevent the accumulation of light, suspended matter in the steam drum it is necessary to ensure that a surface blowdown is accomplished periodically. A scum blowdown is required following the first boiler water sample that is above the lower alkalinity and phosphate limits after coming on the line, provided the boiler has been secured for more than 2 hours, and then weekly, that is, no more than 168 to 192 hours between surface blowdowns. When a surface blowdown is not required due to water chemistry, a superficial, 1 inch surface blowdown (scum blowdown) shall be accomplished. To accomplish this blowdown, establish the boiler water level at 1 inch above the surface blow take-off pipe and then blow down to the pipe. The boiler is sampled and treated as required within 1 hour prior to a scum blowdown, but a sample is not required after the blowdown. Record the scum blowdown as ″S-1″. The percent blowdown is not calculated. The steaming hours since last surface blowdown are zeroed by any surface blowdown and when the boiler is secured for more than 2 hours.

220-22.55 CONTINUOUS BLOWDOWN.

Continuous blowdown of the boiler is accomplished by a low flow of sample through the boiler water sample cooler. Blowdown water is monitored by an in-line conductivity meter. This blowdown removes the chelated metals and other contaminants and prevents excess buildup of treatment chemicals from the continuous treatment system. Continuous blowdown is initiated following the after-on-line sample and is secured when the boiler is secured unless fires will be relit within 2 hours. The procedure for obtaining a boiler water sample and operation of the continuous blowdown system is given in Figure 220-22-6. The flow rate through the in-line cell is manually adjusted and is dependent upon boiler load. Different flow rates are required for steaming at less than 20%, between 20% and 60%, and greater than 60% load. Changes in boiler load of short duration, 4 hours or less, do not require adjustment of blowdown rate. The flow is checked and adjusted as required by the Oil King whenever a boiler water sample is obtained. The flow is also checked and logged hourly by the watch stander. The Fire Room Supervisor shall advise the Oil King of irregularities in the flow. The continuous conductivity is entered on the chelant boiler water log for each sample tested. The continuous monitor is operating satisfactorily when the reading is within 10% of the boiler water sample conductivity. If the continuous meter is not operating satisfactorily, the frequency between boiler water samples shall not exceed 8 hours. The continuous meter is monitored for signs of contamination. The continuous conductivity reading shall be logged hourly in the fireroom operating log. A change in conductivity reading of more than 50 µmho/cm over one hour, not due to batch treatment or surface blowdown, shall be reported to the EOOW and Oil King and a boiler water sample shall then be obtained to determine cause of change.

220-22.56 WATER TREATMENT PRIOR TO SECURING.

Within 90 minutes prior to securing, sample the boiler water. Test the sample. If phosphate is less than 10 or alkalinity is less than 0.100 epm, treat the boiler using Batch Chemical Injection Table 220-22-9. After completing chemical injection, either secure within 90 minutes of the prior to securing sample (use the sample taken one hour prior to blowdown as both the after chemical addition sample 60 to 90 minutes after chemical addition. If treatment is not required, either secure within 90 minutes of the prior to securing sample or continue steaming taking another prior to securing sample within 90 minutes of securing.

BOILER WATER SAMPLING AND CONTINUOUS BLOWDOWN START-UP

WARNING

Wear a face shield when obtaining a boiler water sample.

Conductivity cell will be damaged by high sample temperature. Ensure cooling water flow remains on when continuous blowdown is operating by locking open cooling water inlet and outlet valves. Secure conductivity cell inlet valve immediately whenever cooling water flow is lost.

1. Close sample inlet valve to conductivity cell.

2. Ensure that cooling water valves are open and coolant flow is established.

3. Open sample cooler outlet valve.

4. Fully open sample cooler inlet valves in sequence from boiler to cooler.

5. When sample flashes to steam or has flowed for 5 minutes, throttle sample cooler outlet valve until the sample flow is at a temperature less than 38°C (100°F).

6. Rinse sample bottle and cap several times with the sample water.

7. Collect a full bottle of sample and immediately cap the bottle. Record the time the sample is drawn. For an idle boiler, proceed to the securing procedure given at the end of this figure.

8. For steaming boilers, open the conductivity cell inlet valve, then secure the sample cooler outlet valve.

9. Using a watch and a graduated cylinder, adjust flow as follows:

Boiler Water Volume for Chemical Treatment (Gallons)	Blowdown Rates (ml/minute)		
	Steaming Rate		
	Less than 20%	20 to 60%	Greater than 60%
800 to 1,300	50	100	200
1,400 to 1,800	75	150	300
1,900 to 2,300	100	200	400
2,900 to 3,100	150	300	600

10. Read the conductivity meter. The sample cooler inlet valves and the cooling water inlet and outlet valves remain open whenever the continuous blowdown is in operation.

SECURING BOILER WATER SAMPLE COOLER

1. Close sample valves starting at boiler.

2. Secure cooling water outlet valve.

3. Secure conductivity meter.

Figure 220-22-6. Boiler Water Sampling and Continuous Blowdown.

220-22.57 BOTTOM BLOWDOWN.

Bottom blowdown, after securing a boiler, is accomplished to remove sludge (suspended matter) from the waterdrum and headers. The procedure for bottom blowdown is given in paragraph 220-22.59. The chelant treatment results in significantly less accumulation of sludge in the boiler. Therefore, the interval between bottom blowdowns is increased for chelant treatment. Do not bottom blow a steaming boiler. Blowdowns may be repeated as needed to reduce contamination levels in the boiler, as long as sufficient deaerated feedwater is available. If the boiler is to be dumped because of chemical casualty, bottom blowdown before dumping is still required. Bottom blowdown requirements are:

1. Bottom blowdown shall be performed, whenever the boiler is secured, unless fires are lit again within 2 hours after the boiler was secured.
2. The boiler shall be secured and given a bottom blowdown within 360 steaming hours of the last bottom blowdown.
3. After waterside cleaning the boiler shall be bottom blown within 24 hours of initial light off.

220-22.58

When visual inspection of the drums and headers indicates excessive sludge buildup, or when visible solids or discoloration are observed in boiler water samples, the blowdown frequency should be increased. Blowdown should also be increased after overhaul or waterside cleaning to reduce dirt, debris and suspended solids, and any time visible solids are observed in the sample.

220-22.59 BOTTOM BLOWDOWN PROCEDURE.

See Figure 220-22-7 for a typical blowdown piping arrangement. Blowdown piping materials are specified in NSTM Chapter 221. Conduct bottom blowdown as follows:

1. Sample, test, and chemically treat the boiler water within 90 minutes prior to securing.
2. Secure the boiler and let it stand for at least 1 hour, but no more than 24 hours.
3. Obtain permission to conduct blowdown. Never attempt to bottom blow with less than 100 psi pressure on the boiler.
4. Sample and test the boiler water within 1 hour prior to blowdown.
5. Raise the steam drum water to plus 6 inches.
6. Prepare the blowdown system by opening the overboard discharge valve(s) and the guarding valve(s), in that order.
7. Quickly open the water drum blow valve until 2 inches of water have been blown out and then quickly close the valve. The water drum blowdown should result in approximately a 4 inch drop in water level. Repeat blowdown at each header valve, except allow the water level to drop only 1 to 1-1/2 inches before closing each valve.
8. Do not let the water level drop out of sight in the boiler water level gauge. If hot deaerated feedwater is not available, discontinue the blowdown and note the blowdown points missed in the boiler water log.

NOTE

Ships that repeatedly have incomplete bottom blowdowns must change the order of blowdown from blowdown to blowdown to ensure adequate blowdown of all heaters.

9. On completion of blowdown close the guarding valve(s) and the overboard discharge valve(s) in that order. Open the drain valve to the bilge to ensure tight seating. Close the valve when pressure is relieved. Monel-type guarding and overboard discharge valves require a second shutting after a 15-minute cool down period to prevent leakage. If hot deaerated feedwater is available, raise the steam drum water level to steaming level.

10. Sample and test the boiler water 30 to 45 minutes after the completion of the blowdown.

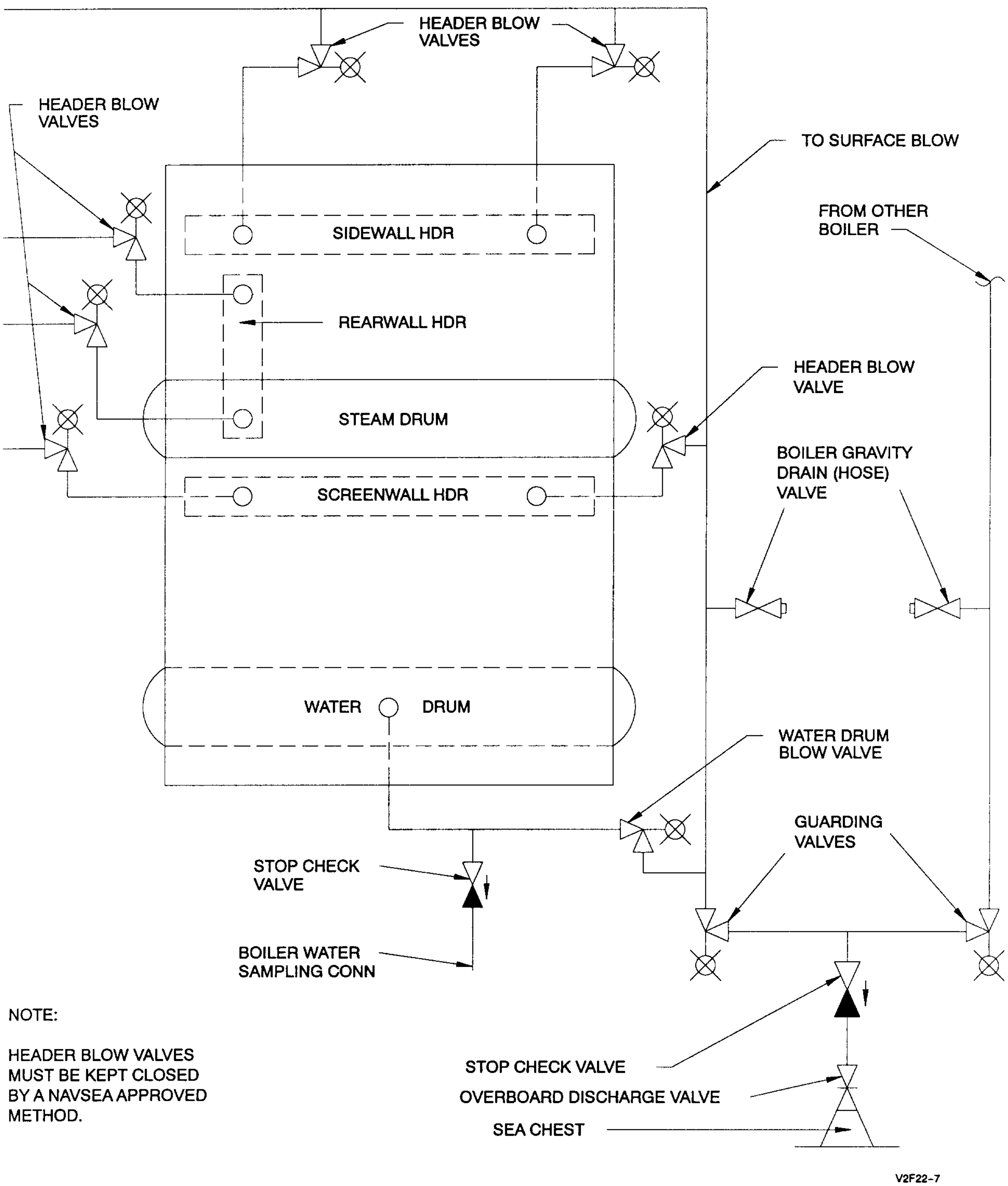


Figure 220-22-7. Boiler Bottom Blow Piping, Typical Arrangement.

220-22.60 IDLE BOILERS.

Refer to NSTM 221-2.2 for care of idle boilers including dry layup, fireside closure, freezing protection and boiler entry.

220-22.61 IDLE BOILER WATER TESTING.

A boiler water sample shall be obtained and tested for alkalinity, phosphate, conductivity and chloride within 1 hour prior to bottom blowdown and 30 to 45 minutes after completing the blowdown. With the exception of hydrazine layup, no further testing or treatment is required for a boiler under wet layup until prior to light-off. Since atmospheric oxygen can be drawn into an idle boiler under wet layup, it is important that the proper procedures for maintaining a positive pressure on an idle boiler be used.

220-22.62 LAYUP OF IDLE BOILERS.

Boiler watersides will begin to corrode as soon as they are exposed to the atmosphere or to water containing oxygen. For this reason a secured boiler that will not be lighted off within 24 hours should be properly laid up as soon as possible after being secured. If a boiler is to be lighted off within 24 hours of being secured, the residual pressure in the secured boiler after bottom blowdown shall be maintained as long as possible; a steam blanket should also be applied. Boilers secured for more than 24 hours shall be laid up using an approved method.

220-22.63 DOCUMENTATION OF LAYUP.

The responsible watchstander shall log layup conditions as specified in pertinent paragraphs. The Oil King shall check and log layup status daily in the boiler water chemistry worksheet/log.

220-22.64 SELECTION OF LAYUP METHOD.

The method of idle boiler layup chosen depends on considerations such as maintenance or repair work planned, planned duration of layup, effectiveness of the layup method, and availability of support for the layup method. Figure 220-22-8 provides guidance for choosing one of the approved idle boiler layup methods discussed below.

220-22.65 COMPARISON OF LAYUP METHODS.

The following is not intended as a list of the various methods by their desirability but only as a summary of the pertinent characteristics of each method.

1. **Hydrazine/Morpholine:**
   a. No time limit.
   b. Provides excellent corrosion protection for boiler watersides, steamsides, and economizer. Preferred method of layup for ships equipped with the continuous treatment system. Provides no corrosion protection for firesides unless heat is applied.
   c. Can be applied at any time by an industrial activity or by ship’s force using the shipboard chelant (EDTA/hydrazine) chemical injection system, provided watersides are intact.
   d. Requires sufficient feedwater to fill the boiler and superheater.
   e. Requires weekly testing of boiler water.
   f. Positive pressure shall be maintained.
   g. Is relatively easy to set up.

h. Is easy to prepare for light-off

i. A boiler can be lighted-off directly from hydrazine layup after draining the hydrazine treated water from the superheater and the steam drum down to the pre-light-off level. All hydrazine treated water removed from the boiler shall be disposed of according to **NSTM Chapter 593, Pollution Control** .

j. Requires special safety and handling precautions.

2. **Steam Blanket:**

a. Time limit - 30 days.

b. Provides reasonable corrosion protection for boiler watersides and superheater. Does not provide for corrosion protection in boiler economizer.

c. Boiler shall be steaming for at least one hour with feedwater dissolved oxygen within limits, or on a hydrazine/morpholine layup, just before application.

d. Requires ship's steam or certified shore steam.

e. Requires periodic blowdown to maintain boiler water level.

f. Is easy to set up

g. Preparation for light-off is easy; no special preparation is required.

3. **Nitrogen Blanket:**

a. Time limit - 30 days.

b. Provides reasonable corrosion protection for boiler watersides and superheater. Provides no corrosion protection for boiler economizer. Provides no corrosion protection for firesides unless heat is applied.

c. Boiler shall be steaming for at least one hour with feedwater dissolved oxygen within limits, or on a hydrazine/morpholine layup, just before application.

d. Requires nitrogen.

e. Requires a relatively leak-free boiler to minimize nitrogen consumption.

f. Is easy to set ;up (if a nitrogen layup system is permanently installed).

g. Preparation for light-off is easy; no special preparation is required.

4. **Sodium Nitrite:**

a. No time limit.

b. Provides excellent corrosion protection for watersides, steamsides, and economizer. Provides no corrosion protection for firesides unless heat is applied.

c. Can be applied at any time provided watersides and steamsides are intact. Unless the ship is in an industrial repair period, use of sodium nitrite for lay-up is prohibited on ships chemically treating boiler water using chelant treatment (EDTA/hydrazine) due to the incompatibility of sodium nitrite with hydrazine.

d. Requires sufficient feedwater to fill the boiler economizer and superheater.

e. Requires maintaining boiler full by use of head tank.

f. Dumping, filling, and flushing are required in preparation for light-off.

g. Shall be disposed of according to **NSTM Chapter 593** .

5. **Hot air:**

a. No time limit.

b. Provides good corrosion protection for watersides, steamsides, economizer, and firesides, provided complete dry-out is achieved.

c. Boiler shall be treated with sodium nitrite before application except in ships using chelant treatment.

Sodium nitrite is not compatible with hydrazine. Ships using chelant treatment need no pretreatment prior to hot air layup. Sodium nitrite is only authorized for use in chelant treated ships when the ship is undergoing an industrial repair period.

d. Can be applied any time.

e. Requires special equipment (heaters and blowers).

f. Is not easy to set up.

g. Requires monitoring of equipment.

h. Requires flushing and disposing of sodium nitrite solution, according to **NSTM Chapter 593** .

i. Hydrostatic testing required before light-off.

6. **Desiccant:**

a. No time limit.

b. Provides reasonable corrosion protection for watersides, steamsides, and economizer, provided complete dry-out is achieved. Provides no corrosion protection for firesides.

c. Boiler shall be treated with sodium nitrite before application except in ships using chelant treatment. Sodium nitrite is not compatible with hydrazine. Ships using chelant treatment require no pretreatment to desiccant layup. Sodium nitrite is only authorized for use in chelant treated ships when the ship is undergoing an industrial repair period.

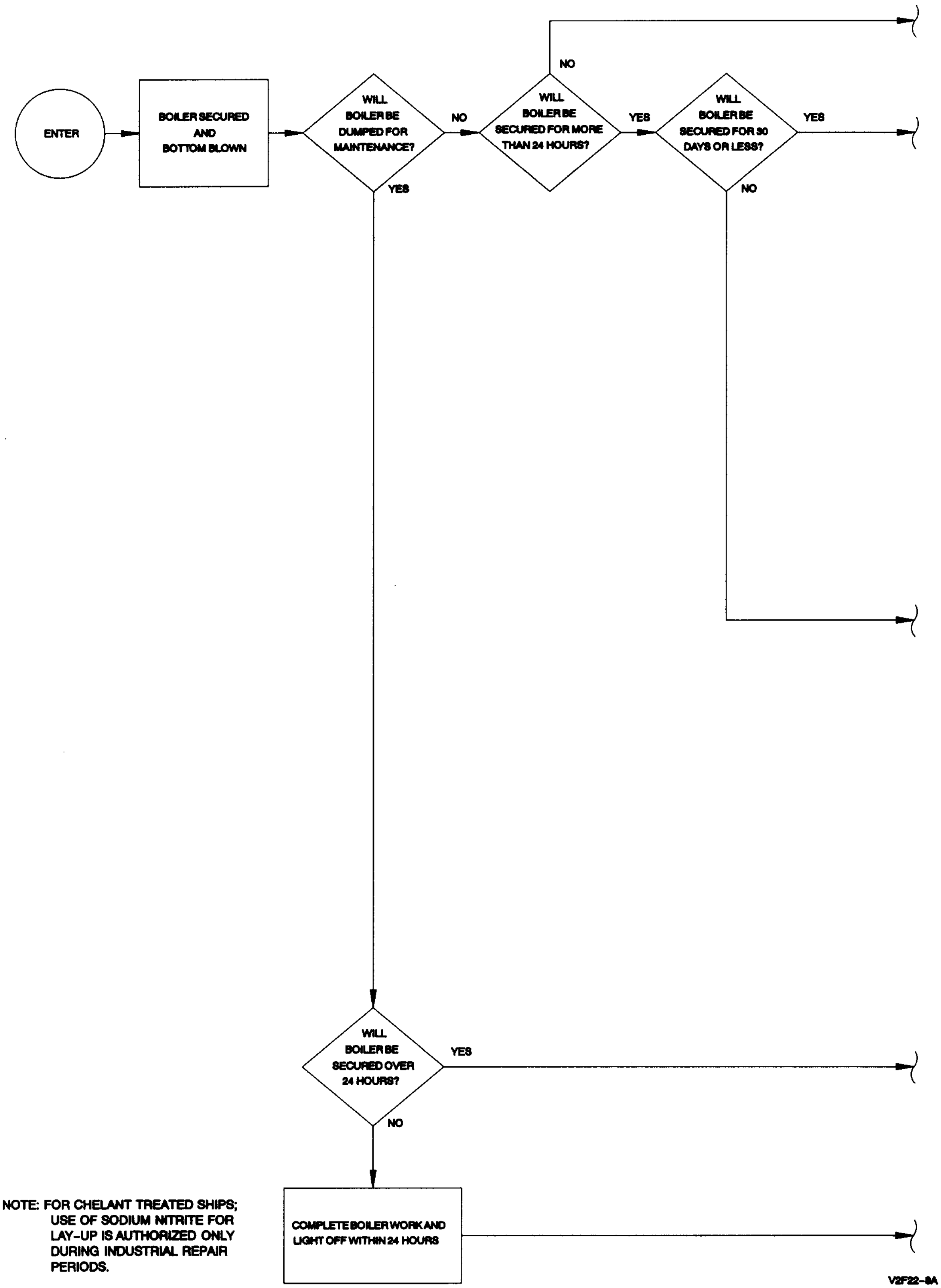
d. Can be applied any time.

e. Is not easy to apply.

f. Requires monitoring of humidity cards.

g. Requires flushing and disposing of sodium nitrite solution, according to **NSTM Chapter 593** .

h. Hydrostatic testing required before light-off.



NOTE: FOR CHELANT TREATED SHIPS; USE OF SODIUM NITRITE FOR LAY-UP IS AUTHORIZED ONLY DURING INDUSTRIAL REPAIR PERIODS.

Figure 220-22-8. Logic Chart for Choosing Boiler Layup Method (Sheet 1 of 2).

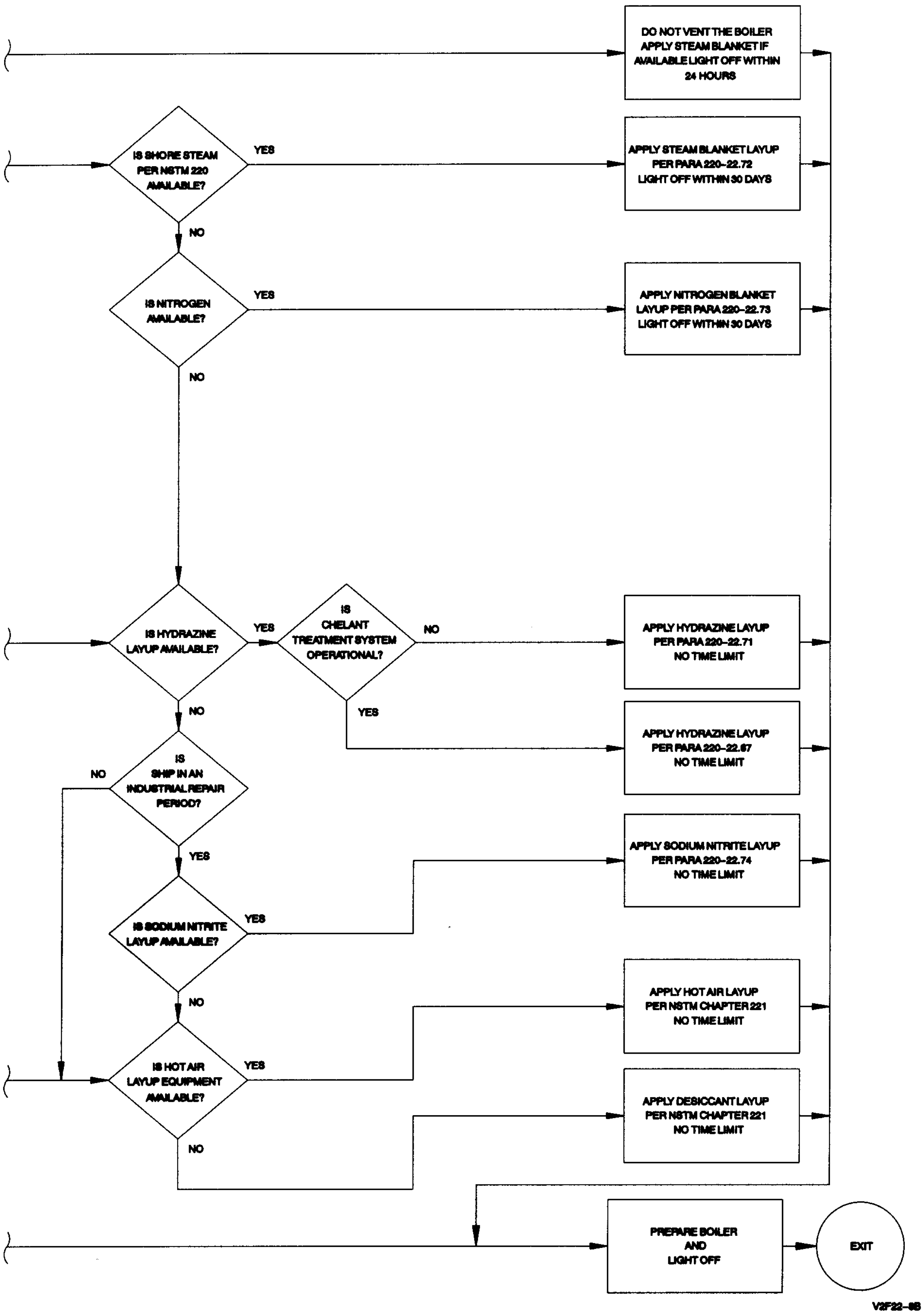


Figure 220-22-8. Logic Chart for Choosing Boiler Layup Method (Sheet 2 of 2).

220-22.66 WET LAYUP METHODS.

Wet layup methods include the following:

1. Hydrazine/morpholine
2. Steam blanket
3. Pure nitrogen blanket
4. Sodium nitrite

NOTE

Steam blanket and nitrogen wet layup may be applied only when the boiler has been steamed for one hour with feedwater dissolved oxygen within limits or on hydrazine-morpholine layup, just prior to application. This limitation does not prohibit the use of superheater protection steam in preparing for boiler light-off. Sodium nitrite wet layup or use of sodium nitrite for any layup is prohibited on ships treating boiler water using chelant treatment unless boilers are undergoing repairs as part of an availability or industrial period.

220-22.67 HYDRAZINE/MORPHOLINE WET LAYUP.

The use of hydrazine/morpholine wet layup by ship's force is authorized in ships equipped with the continuous treatment system. It is the preferred long-term wet layup for ships equipped with the continuous treatment system. Boilers using hydrazine layup shall be tested on the first day of layup and weekly thereafter for hydrazine (paragraph 220-22.32). If the hydrazine level in the boiler water falls below 2.5 ppm, the layup must be reinitiated.

220-22.68

Hydrazine Morpholine Layup Procedure for a Recently Secured Boiler.

1. After boiler is secured:
   a. Drain remaining treatment solution to the bilge.
   b. Prepare 30 gallons of layup solution using 1/2 quart of 40% morpholine and one bottle of 7% hydrazine solution. Thirty gallons of layup solution will be needed for each 2,000 gallons of feedwater to be treated. The total volume of boiler water for layup is given in Table 220-22-11. The procedure for preparing the layup solution is given in Figure 220-22-9. Condensate must be available.
2. After bottom blowdown, when boiler pressure reaches 5 psig:
   a. Ensure boiler water level is approximately normal.
   b. Confirm DFT vent valve is open.
   c. Raise DFT water level to provide sufficient feedwater to fill boiler.
   d. Recirculate DFT using main feed booster pump or emergency feed and transfer pump.
   e. Inject 30 gallons of the prepared treatment solution for each 2000 gallon increment of feedwater in the DFT (30 gallons of treatment solution for up to 2000 gallons of feedwater, 60 gallons for up to 4000 gallons). The procedure for injection of the layup solution is given in Figure 220-22-10. Continue DFT circulation

for 15 minutes and test for hydrazine (220-26.32). The hydrazine concentration should be approximately 20 to 70 ppm. If the hydrazine concentration is less than 20 ppm prepare an additional 30 gallons of layup solution and inject into DFT.

f. Feed the layup solution to the boiler economizer through the main feed connection using the main feed booster pump or emergency feed and transfer pump.

g. Using steam hose, align feed from DFT to boiler superheater or desuperheater backfill connection via the emergency feed and transfer pump.

h. Backfill the boiler with the hydrazine/morpholine treated layup solution. While filling close each vent in turn as the treated water overflows. Wear face shield and gloves.

i. After the boiler is filled as shown by overflow from the highest vent, crack each lower vent in turn to ensure that there are no trapped air pockets.

j. Continue filling until the head tank is full or a positive pressure is maintained on the boiler. Positive pressure may be maintained using booster pump, steam, nitrogen or head tank.

k. The head tank level or boiler pressure shall be monitored and logged hourly by the responsible watch stander. Maintain the head tank level by filling from the treated DFT.

NOTE

During this layup, the firesides should also be protected by heated air or heat lamps.

3. **Lost Layup.** If the hydrazine concentration falls below 2.5 ppm, the layup is lost, and the boiler shall be dumped and retreated or the layup changed. Refer to paragraph 220-22.76 for procedures for changing layup methods.

4. **Time Limit.** There is no time limit on hydrazine layup.

5. **Disposal.** Dispose of the hydrazine/morpholine solution in accordance with NSTM Chapter 593.

6. **Preparation for Light-off.** Dumping and flushing the boiler is not required after hydrazine/morpholine layup. Before light-off, drain the superheater and run down the boiler watersides to the pre-light-off level. Add treatment chemicals as required, through the batch injection system using the initial dosage from Table 220-22-8. A prior to light-off sample is not required following hydrazine layup. Light-off a boiler containing hydrazine/morpholine layup solution may result in false high boiler water phosphate results and high salinity/conductivity indicator readings due to high levels of morpholine. High levels of DFT hydrazine may also be encountered. Refer to paragraphs 220-23.64 through 220-23.66.

WARNING

Boilers shall not be hydrostatically tested with hydrazine/morpholine treated water.

Table 220-22-11. COLD TOTAL BOILER WATER VOLUME FOR LAYUP

Volume (Gallons)	Ships
1,600	AD-15, AD-18, AD-19, AR-5 thru AR-8, AVM-1, FF-1040 Class, FF-1052 Class, FFG-1 Class, FF-1098

Table 220-22-11. COLD TOTAL BOILER WATER VOLUME FOR LAYUP

- Continued

Volume (Gallons)	Ships
2,000	CG-16, CG-17, CG-18, DDG-2, DDG-3, DDG-7, DDG-8, DDG-10 thru DDG-13, DDG-40 thru DDG-46, LSD-36
2,100	DDG-4, DDG-5, DDG-8, DDG-9, DDG-14, DDG-23, DDG-24
2,200	FF-1037, FF-1038
2,300	AGF-3, LPD-1, LPD-2, LPD-4, LPD-5, LPD-6, LSD-28 thru LSD-35
2,400	CG-26 thru CG-34, DD-946, DDG-15 thru DDG-22
2,500	AGF-11, AO-98, AO-99, LPD-7 thru LPD-10, LPD-12 thru LPD-15, LSD-37 thru LSD-40
2,600	CG-19 thru CG-24, DDG-37, DDG-38, DDG-39
2,900	AD-37, AD-38, AD-41 thru AD-44, AFS-1, AFS-2, AFS-3, AS-33, AS-34, AS-39, AS-40, AS-41
3,000	AE-21, AE-22, AGDS-2, AVT-18, LPH-2, LPH-3, LPH-7
3,100	AFS-4 thru AFS-7, CV-41, CV-43, LCC-19, LCC-20, LPH-9, LPH-10, LPH-11
3,200	AE-23 thru AE-25, T-AE-26, AE-27 thru AE-29, AE-32 thru AE-35, AS-36, AS-37, LPH-12
3,800	AOE-1, AOE-2, AOE-3, BB-61 thru BB-64
4,000	AOR-1 thru AOR-7, CV-59 thru CV-64
4,400	AOE-4
4,700	CV-66, CV-67
5,100	LHA-1 thru LHA-5, LHD-1 Class
5,400	AO-177 thru AO-180, AO-186
6,200	LKA-113 thru LKA-117

PREPARATION OF LAYUP TREATMENT SOLUTION

WARNING

Wear face shield, goggles, coveralls, apron, and gloves when handling morpholine and stock hydrazine solutions. If leakage develops put on boots before repairs are accomplished. Test shower/eyewash prior to adding chemicals to ensure cool water is available for emergencies. If chemicals contact skin, flush or shower with cool water. If chemicals enter the eyes, flush with cool water for 15 minutes, raising and lowering eyelids. Seek immediate medical attention.

1. Verify that the following valves are closed: 5, 14, 15, 16, 20, 21, 22, 23 and 24 (Figure 220–21–6).

2. Open valves 9 and 11. Ensure valves 10, 12 and 13 are open. Energize sight flow lights. Verify 0 psig pressure on mixing tank and piercing apparatus.

3. Open valves 6, 7 and 8.

4. Drain mixing tank by opening valves 15 and 16. After draining, close valves 6, 15 and 16.

5. Retract cutter fully by rotating handwheel counterclockwise and remove piercing apparatus cap. Remove empty hydrazine bottle.

6. Pour 1/2 quart of 40% morpholine solution into piercing apparatus.

7. Carefully insert sealed hydrazine bottle into piercing apparatus, check cap o-ring and replace cap. Tighten cap until fully closed.

8. Puncture hydrazine bottle by rotating handwheel fully clockwise, open valve 6 and observe sight flow to determine when addition is complete.

WARNING

The feedwater used to prepare the layup solution must be less than 200°F to prevent melting the hydrazine bottle. Once the hydrazine bottle is punctured, do not open the piercing apparatus until completion of flushing.

9. After hydrazine addition is complete, secure valves 7 and 9.

10. Commence bottle flush. Open condensate flush valve 5. Ensure valves 6, 8 and 11 are open.

11. Continue flush until tank is filled to 28 gallon mark, then secure valves 5. Do not over fill.

12. Open valves 7 and 9 to drain piercing apparatus. Observe sight flows to determine when draining is complete.

13. Secure valves 6, 7, 8, 9 and 11.

14. Turn off sight flow lights.

NOTE

1. Hydrazine bottle must not be used for any other purpose.

2. To insure complete flushing of hydrazine bottle, only one gallon may be added per tank (30 gallons) of layup solution. When multiple batches are required for layup, repeat above procedure. Do not drain mixing tank between doses.

3. Mixing tank must be drained prior to preparing fresh continuous treatment solution.

Figure 220-22-9. Preparation of Layup Treatment Solution.

INJECTION OF LAYUP TREATMENT

1. **Verify that the following valves are closed: 5, 6, 7, 8, 9, 11, 14, 15, 16, 20, 21, 22 and 23 (Figure 220–21–6).**

2. **Ensure that the valves 12 and 13 are open.**

3. **Open nitrogen bottle valve, set nitrogen pressure and the open valve 24.**

4. **A. Layup using DFT: Turn on power to system. Open valve 15, 20, 21 and 22. When solenoid valve closes, secure valves 15, 20, 21 and 22.**

   B. Layup using reserve feed tank: Open valves 17 and then 14. When tank is empty, secure valves 14 and then 17.

5. **Secure nitrogen valve 24.**

6. **Prepare additional batches of layup treatment solution and repeat injection as required.**

7. **Upon completion of layup, drain mixing tank by opening valves 11, 15 and 16. After draining secure valves 11, 15 and 16. Secure power to system.**

Figure 220-22-10. Injection of Hydrazine/Morpholine Layup Treatment.

220-22.69 HYDRAZINE MORPHOLINE LAYUP PROCEDURE FOR AN EMPTY BOILER.

The hydrazine morpholine layup procedure for an empty boiler is the same except that several fills of the DFT may be needed.

220-22.70 HYDRAZINE MORPHOLINE LAYUP PROCEDURE USING THE RESERVE FEED TANK.

The reserve feed tank can be used to provide treated feedwater for boiler layup. Inject 30 gallons of prepared layup solution into the empty feed tank for each 2000 gallons of feedwater required for layup. Add the required feedwater to the tank and then layup the boiler as in paragraph 220-22.68 or 220-22.69.

220-22.71 HYDRAZINE/MORPHOLINE WET LAYUP (INDUSTRIAL ACTIVITY ONLY).

The boiler pressure and head tank level (if provided) shall be monitored hourly and logged each watch by the responsible watchstander. Maintain the head tank water level with feed-quality water, as required.

1. **Responsibility:**
   a. The ship’s Commanding Officer is responsible for:
      (1) Submitting appropriate work requests to the TYCOM for authorization to implement layup.
      (2) Operating ship-installed equipment used in applying the layup, but not including han dling of concentrated treatment chemicals.
      (3) Ensuring that the boiler pressure or head tank level is monitored hourly, logged each watch by the responsible watchstander, and maintained.
      (4) Ensuring that the industrial activity samples the boiler water weekly, that test results are within limits and are recorded in the ship’s boiler water treatment log, and that the industrial activity corrects out-of-limit conditions immediately.

b. The industrial activity is responsible for:

(1) Providing required equipment, qualified personnel, and the necessary chemicals to per form a hydrazine/morpholine layup.

(2) Observing pertinent safety precautions.

(3) Mixing and handling the concentrated hydrazine solution before and while adding it to the feed tank and while filling the boiler.

(4) Sampling and testing the treated boiler water within 1 hour of establishing the layup and weekly thereafter.

(5) Providing test results to the ship's Commanding Officer.

(6) Dumping and retreating, as required, to maintain the hydrazine concentration of the boiler water above 2.5 parts per million (ppm) during the course of the layup.

2. **Safety Precautions.** The following information applies to the use and handling of 15-percent catalyzed hydrazine.

a. In addition to being alkaline and toxic, hydrazine is a reducing agent (a very reactive chemical).

b. Harmful, possible fatal effects may result from ingestion, inhalation of vapors, or prolonged contact with the skin. These effects include dizziness, nausea, hoarseness, headache and dermatitis. When inhaled, it may cause acute and chronic disease of the lungs, liver, kidneys and central nervous system. Both inhalation and contact with the eyes and skin must be avoided.

c. When hydrazine is mixed with feedwater, it rapidly reduces the oxygen dissolved in the water to form water as a product of the reaction. When added to the water in a cold boiler, it slowly reduces rust to magnetic iron oxide.

d. Fifteen-percent catalyzed hydrazine has no flashpoint and does not constitute a fire hazard. Hydrazine is completely insensitive to shock, friction, or electrical discharge.

e. The following handling and safety precautions for 15-percent catalyzed hydrazine shall be strictly adhered to:

(1) Because hydrazine is a strong reducing agent, it shall be stored separately from chlorine, bromine, hypochlorite, nitrite, acids other oxidizers and organics. Do not allow the hydrazine solution to freeze, contact heated surfaces or to stored in direct sunlight.

(2) Hydrazine is alkaline and toxic and may be handled only by qualified shipyard personnel. Operators shall wear the following protective equipment:

(a) Chemical and oil resistant gloves

(b) Protective gloves

(c) Rubber boots

(d) Rubber apron

(e) Chemical worker's goggles

(3) If hydrazine is splashed in the eyes, flush them immediately with water for 15 minutes lifting upper and lower lid occasionally. Seek medical attention. Skin areas affected by either stock or treatment solution shall be flushed immediately with cold water for 15 minutes. Seek medical attention if skin feels itchy or slippery. Launder any clothes that have been contaminated with stock or dilute hydrazine solution before wearing.

(4) If hydrazine is swallowed, induce vomiting with 1 tablespoon syrup of Ipecac or two glasses of warm saline solution, and consult a physician immediately.

(5) Personnel shall wear chemical workers goggles, chemical and oil resistant gloves, rubber boots, and rubber apron during spill clean-up of both stock and treatment solutions.

(6) Abbreviated procedures for spill clean-up follow.

(7) Immediately follow a hydrazine spill that occurs in a machinery space, passageway, or storage area, personnel not wearing protective gear shall be evacuated.

(8) If hydrazine is spilled in a space which exhausts outside the ship, maintain ventilation at the maximum level until cleanup is completed.

(9) Hydrazine is alkaline and toxic and may be handled only by qualified shipyard personnel. Operators shall wear the following protective equipment:

(10) If hydrazine is swallowed, induce vomiting with 1 tablespoon syrup of Ipecac or two glasses of warm saline solution, and consult a physician immediately.

(a) Spread 10 pounds of absorbent on the spill for each gallon of 15-percent hydrazine solution spilled.

(b) Collect the absorbent using metal dustpans and place it in a polyethylene bag.

(c) Seal the polyethylene bag in a labeled metal drum for disposal ashore.

3. **Procedure:**

a. Determine the volume of water which is required to completely fill the boiler, superheater, and economizer by consulting Table 220-22-11. Add about 500 gallons to that total for reserve.

b. Empty a feed tank as far as possible. Ensure that the feed tank will hold the quantity of feedwater calculated. The feed tank will be used to mix the hydrazine/morpholine solution.

c. Drain all water from the boiler, superheater, and economizer.

d. Close all boiler drains and openings with the exception of the steam drum, superheater, and economizer vents.

e. Each 1,000 gallons of water to be added to the feed tank requires 2,500 milliliters (2/3 gallon) of catalyzed 15-percent hydrazine and 375 milliliters (4/5 pint) of 40-percent morpholine. Transfer the required amount of hydrazine into narrow mouthed 1-gallon or 2-gallon polyethylene bottles (with polyethylene or polypropylene screw closures). Transfer the required amount of morpholine to a pint, quart, or gallon polyethylene bottle, as appropriate to the volume needed. Pour the morpholine and hydrazine down the feed tank sounding tube. Flush the tube with about 3 gallons of feedwater.

f. Immediately fill the feed tank with feedwater to the level calculated in step a. of this procedure for the quantity of hydrazine/morpholine solution desired.

NOTE

The hydrazine/morpholine solution may be prepared in a pierside tank and pumped into the boiler.

g. Immediately fill the boiler (watersides) through the main feed connection. Backfill the boiler via the superheater or desuperheater backfill connection using either the emergency feed booster pump or emergency feed pump.

h. While filling the boiler, close each vent in turn as the treated water overflows.

i. After the boiler is filled, as shown by an overflow from the highest vent, crack each lower vent in turn to ensure that there are no trapped air pockets.

j. Using the treated water left in the reserve feed tank and a feed booster pump or other suitable pump under continuous recirculation, maintain positive pressure on the boiler not to exceed 150 psig. The use of a head tank, nitrogen, or steam to maintain positive pressure is also permissible.

WARNING

Boilers shall not be hydrostatically tested with hydrazine/morpholine treated water.

k. When the boiler is under layup, the industrial activity shall determine the hydrazine concentration on the day the layup begins and weekly thereafter. Draw a sample through the boiler water sample line after allowing the boiler water to flow for 5 minutes to flush the line. Allow the sample bottle to overflow before capping the bottle to eliminate trapped air. Determine the hydrazine concentration as soon as possible (and no more than 1 hour after sampling). The hydrazine concentration will normally be between 30 and 70 ppm.

NOTE

During this layup, the firesides should also be protected by heated air or heat lamps, if available.

4. **Lost Layup.** If the hydrazine concentration falls below 2.5 ppm, the layup is lost, and the boiler shall be dumped and treated again or the layup changed. Refer to paragraph 220-22.76 for procedures for changing layup methods.
5. **Time Limit.** There is no time limit on hydrazine layup.
6. **Disposal.** Dispose of hydrazine/morpholine solution according to **NSTM Chapter 593** .
7. **Preparation for Light-off.** Dumping and flushing the boiler is not required after hydrazine/morpholine layup. Before light-off, drain the superheater and run down the boiler watersides to the pre-light-off level. Inject chemicals using the freshly filling dosage from Table 220-22-8. A prior to light-off sample is not required following hydrazine layup. Light-off of a boiler containing hydrazine/morpholine layup solution may result in false high boiler water phosphate results and high salinity conductivity indicator readings due to high levels of morpholine. High levels of DFT hydrazine may also be encountered. Refer to paragraphs 220-23.64 through 220-23.66.

220-22.72 Steam Blanket Wet Layup.

Steam blanket pressure and steam drum water level shall be monitored hourly and logged each watch by the responsible watchstander. A typical steam blanket piping arrangement is shown in Figure 220-22-11.

1. Prerequisites.
   a. Superheater drained.
   b. Steam from the 150 psig auxiliary system shall be supplied from another shipboard boiler or from a certified shore source. If steam from another shipboard boiler is used, the feedwater being supplied to that boiler shall meet the dissolved oxygen requirements of paragraph 220-22.15. If shore source steam is used, the steam shall be certified by the supplying activity to meet the requirements of paragraph 220-22.18.
   c. Boiler shall be steaming for a least 1 hour with the feedwater dissolved oxygen within limits or on a hydrazine/morpholine layup, just before application.
   d. Only deaerated feedwater meeting the requirements of paragraph 220-22.15 shall be supplied to the boiler after securing.
   e. Boiler pressure shall not fall to atmospheric pressure before the steam blanket is applied.
2. Procedure.

a. Close all vents, high pressure (HP) drains, and other connections.

b. Open the steam blanket valve to the boiler when the boiler pressure falls to that of the steam blanket supply.

c. Maintain the water level in the visible range of the sight glass by using surface blow.

CAUTION

If steam pressure is below 50 psig or drops below 50 psig while surface blowing, the surface blow shall not commence or shall be secured until such time steam pressure can be restored. If all steam pressure is lost and boiler layup is voided, water may be run down to the bilge.

d. Crack open all superheater header and desuperheater low-pressure (LP) drains to the freshwater drain, if installed, or to the bilge. The HP drain system will not adequately remove superheater condensate during this type of layup.

3. **Lost Layup.** Steam blanket layup is considered lost when the boiler steam pressure falls to atmospheric pressure and cannot be reestablished. If the steam pressure cannot be verified using installed pressure gauges, check for the presence of steam pressure by cracking a boiler vent. Refer to paragraph 220-22.76 for procedures for changing layup methods.

NOTE

Operating ships may interrupt steam or nitrogen blanket pressure to perform emergent repairs. Such maintenance should be performed as close to scheduled boiler light-off as possible to minimize oxygen corrosion. The interruption of steam or nitrogen blanket pressure shall only be done once per layup period. The time the blanket pressure is interrupted should be minimized as much as possible and shall not exceed 8 hours. The 8 hour period begins when the blanket pressure falls to atmospheric. If extensive maintenance/repairs are required, the boiler should be laid up dry.

4. **Time Limit.** Light-off the boiler within 30 consecutive days of securing or dump and apply hydrazine, sodium nitrite, or dry layup. The boiler may be shifted to nitrogen blanket layup provided the pressure is maintained above atmospheric and the combined steam and nitrogen blanket layup does not exceed 30 consecutive days after securing.

5. **Preparation for Light-off.** Before light-off, check that the superheater is drained and that the steam drum water level is proper for light-off.

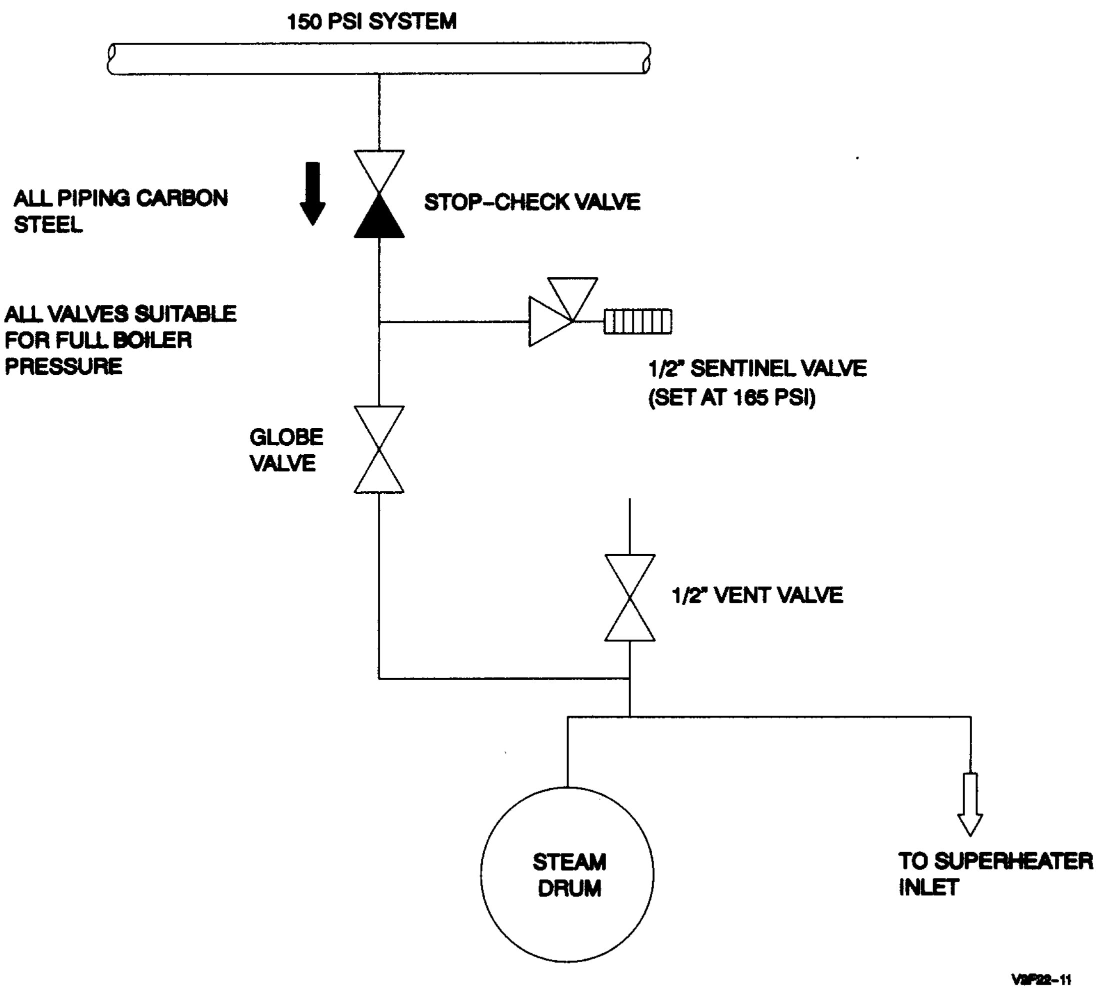


Figure 220-22-11. Typical Steam Blanket Piping Arrangement.

220-22.73 NITROGEN BLANKET WET LAYUP.

Nitrogen pressure shall be monitored hourly and logged each watch by the responsible watchstander.

1. Prerequisites:
   a. Superheater drained.
   b. Nitrogen tanks available.
   c. Boiler shall be steaming for at least 1 hour with the feedwater dissolved oxygen within limits or on a hydrazine/morpholine layup, just before application.
   d. Only deaerated feedwater meeting the requirements of paragraph 220-22.15 shall be supplied to the boiler after securing.
2. Procedure:
   a. Close all vents, drains, and other connections.
   b. Maintain water at the normal steaming level.
   c. Maintain a minimum nitrogen pressure on the boiler of 5 psig at all times, monitored at the nitrogen tank regulator. Use water pumped nitrogen, 99.5 percent pure by volume.

NOTE

During this layup, the firesides should also be protected by heated air or heat lamps, if available.

3. **Lost Layup.** Nitrogen blanket layup is considered lost when nitrogen pressure is lost and cannot be reestablished. Refer to paragraph 220-22.76 for the procedure for changing layup method.

NOTE

Operating ships may interrupt steam or nitrogen blanket pressure to perform emergent repairs. Such maintenance should be performed as close to scheduled boiler light-off as possible to minimize oxygen corrosion. The interruption of steam or nitrogen blanket pressure shall only be done once per layup period. The time the blanket pressure is interrupted should be minimized as much as possible and shall not exceed 8 hours. The 8 hour period begins when the blanket pressure falls to atmospheric. If extensive maintenance/repairs are required, the boiler should be dry.

4. **Time Limit.** Light-off the boiler within 30 consecutive days or dump and layup using hydrazine, sodium nitrite, or dry layup. The boiler may be shifted to steam blanket layup provided pressure is not lost, certified steam is used and the combined nitrogen and steam blanket layup does not exceed 30 consecutive days from securing.

5. **Preparation for Light-off.** Before light-off, check that the superheater is drained and the steam drum water is at the proper level.

220-22.74 Sodium Nitrite Wet Layup.

The sodium nitrite wet layup method, used only during industrial periods, involves filling the boiler, economizer, and superheater with feed-quality water treated with sodium nitrite and maintaining the boiler full with a head tank or by using a booster pump. Sodium nitrite layup may be applied any time the boiler watersides and steamsides are intact. The responsible watchstander shall check the head tank level or booster pump discharge pressure hourly to ensure a positive head is maintained. The watchstander shall also log each watch that the head tank level or booster pump discharge pressure has been maintained.

1. **Prerequisites:**
   a. Sodium nitrite, 10 pounds per 1,000 gallons feedwater required.
   b. Head tank above the highest vent, if a booster pump is not to be used to maintain positive pressure.

2. **Procedure.**
   a. After the boiler is secured and boiler pressure falls to zero psig, the economizer and the entire boiler shall be dumped.
   b. Use Table 220-22-11 to determine the volume of sodium nitrite solution required to fill the boiler economizer, and superheater. Add 500 gallons to that amount.
   c. Prepare the volume of sodium nitrite solution required in a pierside tank or ship's DFT by mixing 10 pounds of sodium nitrite with each 1,000 gallons of feed-quality water required. Mixing is accomplished by pre-dissolving the dry sodium nitrite (10 pounds in 2 gallons of feed-quality water) and then adding the concentrated solution to the feedwater in the pierside tank or ship's DFT, followed by recirculating the

pierside tank or DFT for 1/2 hour. The DFT may be treated by pumping the concentrated solution through the gauge glass run-down line, using the pump specified for EDTA cleaning in **NSTM Chapter 221** or another suitable pump.

d. Fill the economizer and boiler to the top of the gauge glass and backfill the superheater with feed-quality water treated with sodium nitrite until the head tank is full if a booster pump is not to be used to maintain positive pressure. Boilers not equipped with backfill connections may be filled through the feed connection, provided boiler watersides are dumped before sodium nitrite layup is applied.

e. While filling the boiler, close each vent in turn when treated water overflows.

NOTE

During this layup, the firesides should also be protected by heated air or heat lamps, if available.

3. **Lost Layup.** Sodium nitrite layup is considered lost when the head tank level or booster pump discharge pressure is not maintained and cannot be re-established. Refer to paragraph 220-22.76 for procedures for changing the layup method.

4. **Time Limit.** Sodium nitrite layup has no time limit.

5. **Disposal.** Disposal of sodium nitrite solution according to **NSTM Chapter 593** .

CAUTION

Sodium nitrite adversely affects the water chemistry in a steaming boiler.

6. **Preparation for Light-off.** To prepare for steaming, dump the boiler, economizer, superheater, and DFT, and drain the associated recirculation piping. Flush by refilling the boiler, economizer, superheater, DFT, and associated recirculating piping with feed-quality water and dumping. Do not light-off with sodium nitrite solution in the boiler or DFT.

220-22.75 DRY LAYUP METHODS.

Refer to **NSTM Chapter 221** for dry methods of layup.

220-22.76 LAYUP CHANGE.

Changing from one layup method to another is authorized only as follows:

1. From steam blanket to nitrogen blanket and vice versa, provided blanket pressure is continuously maintained and the total time of blanket layup (steam and nitrogen combined) does not exceed 30 consecutive days from securing.

CAUTION

Sodium nitrite is chemically incompatible with hydrazine. Store these chemicals separately. Do not mix sodium nitrite and hydrazine solutions.

2. From any wet or dry method to hydrazine/morpholine or sodium nitrite layup, with the special restrictions given below:

a. To prepare for the transition from sodium nitrite wet layup to hydrazine layup, dump the boiler, economizer, superheater, and DFT, and drain associated recirculation piping. Flush by refilling the boiler, economizer, superheater, DFT, and associated recirculating piping with feed-quality water and dumping.

b. To prepare for the transition from dry layup to hydrazine layup, flush the boiler with feed-quality water and dump. Do not apply hydrazine layup with sodium nitrite solution in the boiler or DFT.

c. Boilers under steam blanket or nitrogen blanket layup shall be dumped before sodium nitrite layup is applied.

3. From any wet to any dry method.

4. From desiccant to hot air and vice versa.

5. Ships using chelant treatment may change from any layup to hydrazine and vice versa with the following exceptions:

   a. Sodium nitrite wet layup is prohibited unless the ship is in an industrial repair period.

   b. Dry layup should be accomplished without the addition of sodium nitrite to the boiler prior to draining unless the ship is in an industrial repair period.

   c. Hydrazine layup replaces hot deaerated fill wet layup.

220-22.77 Lost Layup.

If a layup is lost, as defined above in each individual method, the boiler shall be lighted off within 24 hours or an alternative layup method applied as specified in paragraph 220-22.76. This applies in all cases except desiccant layup, where saturated desiccant can be replaced or dried out.

220-22.78 PRIOR TO LIGHT-OFF.

Within 1 hour preceding boiler light-off, sample and test the idle boiler water for conductivity, alkalinity, phosphate, and chloride. This sample is not required for a freshly filled and treated boiler, following hydrazine layup, or when the boiler has been secured for less than 2 hours. Take the following actions based on the sample results:

1. If the test results are within limits, light-off the boiler. If light-off is delayed beyond 1 hour another prior to light-off sample is required.

2. If the conductivity result is above the upper limit, find and correct the cause of the contamination, dump and freshly fill and treat.

3. If alkalinity or phosphate is below lower limit, batch treat using Table 220-22-9. No further sampling is required until after the boiler is on-line.

220-22.79 BOILER WATER SILICA

220-22.80

Silica is boiler water is capable of forming a scale on the boiler watersides. It may also be volatilized along with steam to deposit on or erode steam turbine blades. Because of scaling and volatility ascribed to boiler water silica, it is important to understand the sources, detection methods, and corrective actions for silica contamination.

220-22.81 SOURCES.

Silica may enter the boiler water from several sources as described in the following paragraphs.

220-22.82 Shore Potable Water.

Shore potable water can contain silica in concentrations up to 30 ppm. Failure of water heater steam coils or use of steam/water mixing valves in the galley or the laundry sections of the service steam system can contaminate the freshwater drains with shore water when the ship’s potable water system contains shore water. The freshwater drains then introduce silica into the condensate which ultimately results in boiler water silica contamination.

220-22.83 Shore Steam.

Shore steam can be contaminated with silica if proper control of the shore boiler and steam distribution systems is not maintained. The use of shore steam for idle boiler layup, as a feedwater source, and as superheater protection steam during light-off shall be limited to steam that has a silica content of 0.2 ppm, maximum.

220-22.84 Shore Source Feedwater.

Shore source feedwater, produced through demineralization of shore water by means of a mixed-bed or dual-bed ion exchange resin, can contain silica. Silica forms a weak bond with the ion exchange resin. As the resin approaches the exhaustion point, the silica, contained in the resin from the previous water passed through the resin, is released into the effluent. Therefore, the silica content of the demineralized water is higher, at this point, than the silica content of the shore water being demineralized. Conductivity measured at the output of the demineralizer does not indicate that silica may be present in the water.

220-22.85 Boiler Maintenance.

Boiler maintenance procedures may also provide a source for boiler water silica contamination. During overhaul of a boiler, some of the steam drum internals may be blasted with sand. In addition, sandblasting is routinely performed on feed tanks and hull plating. The fine sand, if not entirely removed from the crevices of the internals or feed and boiler systems’ piping, can cause boiler water silica contamination. In addition, refractory dust can enter the watersides if exposed during maintenance operations, serving as a boiler water silica source.

220-22.86 Boiler Layup.

Desiccants used in boiler layup all contain silica-bearing materials. Desiccant materials left in the boiler will cause silica contamination of the boiler water.

220-22.87 PREVENTION.

Prevention of silica contamination requires the following precautions:

1. Eliminate shore water contamination of the service steam drain system.
2. Use only shore source feedwater and steam that meet the requirements of paragraph 220-22.18 or 220-22.20.
3. Perform boiler maintenance work only with silica-free materials when practicable. When silica or silicate containing materials must be used for sandblasting boiler internals or there is a possibility of refractory dust set-

tling on the watersides, hose down the entire steam drum internal surface with feedwater, flush through each feedwater circuit, and drain through the water drum and header drain connections upon completion of all maintenance work.

220-22.88 DETECTION.

The silica test shall be used by ships for testing silica in shore source feedwater or shore steam condensate. This does not change the requirement for obtaining certification from the supplier of the shore source feedwater or shore steam condensate. The silica test can also be used by ships for testing silica in boiler water. Activities providing feedwater and steam to ships shall use the American Society for Testing and Materials Method (ASTM) D-859 or equivalent commercial test kit. Water samples for any silica test shall be provided in plastic (polyethylene) quart bottles. Glass bottles shall not be used when sampling for silica. Boiler water silica is not normally encountered in operation at sea unless makeup feed from a shore source is being used or shore water is in the potable water tanks. The feedwater from shore shall meet the requirements of paragraph 220-22.18 or 220-22.20. Shore potable water contamination can be detected by the hardness test (paragraph 220-26.18) performed on the service steam drains. It should be noted that shore potable water contamination of the service steam drains tends to be intermittent.

220-22.89 LIMITS AND CORRECTIVE ACTION.

Undesirable steam silica contamination occurs when the boiler water silica exceeds 5 ppm for 1200 psi boilers and 30 ppm for 600 psi boilers. The immediate corrective action for excessive silica in the boiler water is surface blowdown. Experience has indicated that silica contamination problems occur more frequently following a regular overhaul period or when extensive repair work has been accomplished on a boiler. For this reason, specific silica control procedures for steam propulsion systems undergoing testing after overhaul or extensive boiler repairs are as follows:

1. Sample boiler water and all feed tanks prior to initial light-off and test for dissolved silica. If boiler water silica is 2 ppm or more, dump the boiler water and refill the boiler with feedwater containing no more than 0.4 ppm silica. This limit does not change the established requirements for shore source feedwater, but takes into account an acceptable level of silica which may be contained in a feed tank. If a feed tank silica is greater than 0.4 ppm, dump and refill with feedwater containing no more than 0.2 ppm.

2. Monitor the freshwater drain collection tank (FWDCT) for silica and hardness. Do not send the freshwater drains to be feed system until their integrity has been established by low silica, 0.10 ppm or less, and low hardness, 0.02 epm or less.

3. Upon initial light-off in the shipyard, sample boiler water, DFT, makeup feed tank, and the FWDCT after the boiler reaches operating pressure. Test samples for dissolved silica. Sample the same elements every 8 hours of steaming and also sample the boiler water prior to and after blowdown. Continue the 8-hour sampling sequence for silica until there are four consecutive boiler water silica results of 10 ppm or less. At this point, feed tanks should have a silica content of 0.20 ppm or less.
    a. For boiler water silica at 10 ppm or less, no unusual action is required.
    b. For boiler water silica above 10 ppm, apply surface blowdown to maintain boiler water in the 10 ppm area.
    c. For boiler water silica that reaches or exceeds 20 ppm, complete equipment test that is under way, secure, and bottom blow. Following this action, the next prior-to-light-off sample shall be 15 ppm or less of silica. If the silica is greater than 15 ppm, drain a portion of the boiler water and refill with qualified feedwater until the prelight-off test for silica shows 15 ppm or less.

4. Continued steaming of the boiler with normally scheduled blowdowns, using makeup feed derived from sea-

water distillate, will result in an acceptable boiler water silica level of 5 ppm or less without incurring a risk of developing serious waterside or turbine silica deposits. No further sampling or testing is required.

220-22.90

The same sampling, testing, and prior-to-light-off requirements described for 1200 psig boilers apply to 600 psig boilers following an overhaul period or extensive boiler repairs except that the upper limit for silica shall be 30 ppm. For 600 psig boilers, if silica contamination is present after light-off and is greater than 30 ppm, surface blowdowns shall be applied to reduce the silica level to 30 ppm.

NOTE

Dissolved silica test results become more realistic as a boiler reaches its operating temperature and pressure.

220-22.91

Silica contamination also occurs when desiccant bags are left in a boiler after dry layup, and when shore source feed is contaminated by silica. If silica contamination is indicated by boiler water results as described in paragraphs 220-23.21.5 and 220-23.21.6, then test boiler water for silica.

220-22.92

The silica limits discussed in preceding paragraphs specify levels that are applied to minimize turbine damage. Silica levels in excess of 5 ppm in any boiler will cause problems in boiler water phosphate analyses. Phosphate results will be high. See paragraphs 220-23.21.5 and 220-23.21.6.

SECTION 23.

CASUALTY CONTROL

220-23.1 INTRODUCTION

220-23.2

This section discusses casualties that may occur in plant chemistry control. The principles of casualty control are discussed in paragraphs 220-23.3 through 220-23.69. Outline procedures for casualty control are given in paragraphs 220-23.70 through 220-23.84. A guide table for quick reference to casualty control procedures is given at the end of the section and is discussed in paragraph 220-23.85.

220-23.3 PRINCIPLES OF CASUALTY CONTROL

220-23.4 GENERAL.

Casualties in plant chemistry control require prompt, well directed action to prevent or minimize plant damage. Plant casualty control procedures must be invoked to stop damage and to return conditions to normal. Troubles in monitoring chemistry conditions as a result of defective indicating devices, test equipment, sampling systems, or test chemicals may mask the symptoms of a casualty. These must be corrected in order to permit proper monitoring and control of plant chemistry.

220-23.5 RECOGNITION OF A CASUALTY.

Effective corrective action depends on timely recognition of a plant chemistry casualty. This in turn depends on all indicating systems and test equipment being in good working order and on watch standers being trained so that they recognize abnormal conditions. Casualties may be indicated by sample results, salinity/conductivity indicator readings, abnormal noises, temperatures, or pressures, high bilge water level, or some other unusual condition, which may occur anywhere in the plant. The Engineering Officer of the Watch (EOOW) must be thoroughly familiar with overall plant arrangement, principles of plant operation, symptoms of chemistry casualties, and casualty control procedures, so that he can properly evaluate reported abnormalities, identify the casualty and initiate appropriate corrective action. The Engineer Officer, MPA, and Oil King must be thoroughly familiar with all aspects of plant operation and chemistry control so that they can properly direct or advise the EOOW, can oversee corrective action, and can give timely, accurate information and advice to the Commanding Officer and Officer of the Deck.

220-23.6 CONFLICTING SYMPTOMS.

Initial symptoms of a casualty may be confusing or even appear to conflict with each other. The fundamental rule of good engineering practice **- Believe your indications -** means that action should be taken based on the worst symptom. If follow-up investigation shows the problem to be less severe, corrective actions can be easily adjusted. On the other hand, if an initial symptom of a serious problem is disregarded, severe plant damage may occur before effective action is taken to correct the problem.

220-23.7 SERIOUS CONTAMINATION OF BOILER WATER

220-23.8

Damage to the boiler or other parts of the plant will occur if boiler water is seriously contaminated. The damage may involve boiler scale formation, corrosion, or water carryover with the steam into the superheater. The types of damage and the conditions under which they will occur are:

1. **Scale formation** may occur if the boiler is steaming with either:
   a. Alkalinity less than 0.050 epm.
   b. Phosphate less than 5 ppm.
2. **Acid corrosion** will occur if the boiler water alkalinity is 0 epm. This will happen whether the boiler is steaming or idle.
3. **Caustic corrosion** will occur if the boiler water alkalinity is greater than 2.000 epm.
4. **Excessive carryover** will occur if the boiler is steaming under any of the following conditions:
   a. Conductivity of the boiler water is more than 2,000 µmho/cm.
   b. The boiler water sample contains oil.
   c. Foaming is visible in the boiler gauge glass.
5. **Oxygen Corrosion** will occur, causing pitting if water containing oxygen enters the boiler. Corrosion will increase if seawater contamination also occurs.

220-23.9 CRITERIA.

Boiler water contamination is serious if it causes any of the following conditions:

1. Alkalinity greater than 1.500 epm.
2. Alkalinity less than 0.050 epm.
3. Phosphate less than 5 ppm.
4. Conductivity more than 1,500 µmho/cm.
5. Dissolved oxygen in the feedwater entering the boiler is greater than 15 ppb for more than 4 hours after detection.

A test result that is outside normal limits, but does not meet the conditions of serious contamination is defined as moderate contamination.

NOTE

Alkalinity less than 0.05 epm or phosphate less than 5 ppm in the after on-the-line (AOL) sample is not moderate or serious contamination unless other criteria are met.

220-23.10 SIGNIFICANT DAMAGE CONDITIONS.

Significant and rapid damage can occur when any of the following conditions exists:

1. Alkalinity is 0 epm.
2. Alkalinity is greater than 2.000 epm.
3. Phosphate is 0 epm.
4. Conductivity is greater than 2,000 µmho/cm.
5. Carryover of boiler water with the steam.
6. Dissolved oxygen in the feedwater entering the boiler is greater than 40 ppb for more than 2 hours after detection.

NOTE

The use of emergency cold suction should be avoided if at all possible, or minimized if it must be used by virtue of system design. Use of emergency cold suction causes entry of cold oxygenated water containing up to 8,000 ppb of dissolved oxygen directly into the boiler. Its use must be treated as any other high dissolved oxygen casualty.

220-23.11 ACTION.

Serious contamination of boiler water defined in paragraph 220-23.9 is a major casualty that demands immediate corrective action. Corrective actions must:

1. Control further damage.
2. Locate and isolate the source of contamination.
3. Remove contamination from the boiler water.

4. Make the plant ready to resume normal operation.

The following paragraphs describe the appropriate corrective actions. During serious contamination, boiler water samples are obtained 15 to 30 minutes after chemical addition or blowdown until boiler water has been returned to moderate contamination or normal limits.

NOTE

If oil contamination has occurred, check salinity indicators for proper operation by chemical comparison test.

220-23.12 Control Damage.

Damage can be controlled by one or more of the following actions as required:

1. Securing the boiler (or minimizing the firing rate).
2. Injecting treatment chemicals to restore alkalinity and phosphate.
3. Blowdown.
4. Restoring DFT to proper operation.

220-23.13 Secure the Boiler.

Securing the boiler will stop all damage except acid and oxygen corrosion. Securing will reduce the effects of acid and oxygen corrosion. If the problem with the DFT cannot be corrected within 8 hours of detection, the boiler must be secured unless continued steaming is directed by the Commanding Officer. If the boiler must be steamed under serious contamination conditions, the steaming rate should be minimized.

220-23.14 Guidance for Securing the Boiler.

When a boiler is seriously contaminated, prompt, well-directed action may result in regaining control of the casualty while the boiler is on-line at minimum load. In a few cases it is necessary to remain on-line to protect ship’s safety, or to locate and correct the contamination source, or to avoid damaging another boiler.

220-23.15

If conditions reach a point of significant damage, the conditions must be controlled, the boiler must be treated and secured as soon as possible, and the contamination must be removed.

220-23.16

The following can be expected to occur under conditions of significant damage:

1. When alkalinity is 0 epm, the boiler water can contain hydrochloric acid (from seawater reactions) or sulfuric acid (from resin decomposition). Seawater contamination resulting in hydrochloric acid formation causes rapid and dangerous corrosion. Tube failures will occur within a few hours. Sulfuric acid from resin contamination is less dangerous in terms of catastrophic failure but tube failures can occur within a few days. Acid attack is suspected to be a contributor to crevice corrosion in drums and headers.

2. When alkalinity is above 2.0 epm and deposits are present, caustic corrosion can occur. Tube failure may result.
3. With no phosphate present, scaling may occur. Acid or caustic attack will occur depending on the alkalinity and this may be the greater immediate problem. Tube bulging and overheat from scaling will occur. The time to proceed to tube failure from scaling is not known but the process is probably slow (greater than a year).
4. A boiler which is experiencing severe, acute carryover can suffer superheater failure in 15 minutes to 1 hour. Chronic minor carryover will result in loss of the superheater in 3 to 6 months. Turbine blade damage will occur over a longer unknown time frame.
5. A boiler steaming with uncontrolled oxygen contamination in feedwater will require retubing in 6 to 9 months. Oxygen contamination is suspected to be a contributor to crevice attack in drums and headers.

220-23.17

Damage to the plant is cumulative. Once it has occurred, equipment cannot be returned to an undamaged condition.

220-23.18

When a condition of serious contamination other than dissolved oxygen is discovered, and one treatment action (chemical or blowdown) does not correct that condition, it is better to secure rather than to remain on-line for the sole purpose of treating or blowing down. Addition of treatment chemicals will be successful only while on-line, or immediately after securing. Only treat once after securing because further chemical addition will not be effective due to inadequate circulation. If after securing, treating and bottom blowing the boiler, the boiler water conductivity is greater than 1500 µmhos, the boiler must be dumped.

220-23.19 Inject Chemicals.

To maintain alkalinity and phosphate within limits, use Table 220-22-9 and add treatment chemicals using the batch chemical injection system shown in Figure 220-22-4. If the boiler is secured before injection of chemicals, add the chemicals immediately after securing.

220-23.20 Locate and Isolate the Source of Contamination.

This should be done concurrent with securing and treating the boiler as discussed above. Locating the source of contamination depends on identifying the type of contamination. Refer to paragraph 220-23.21.

CAUTION

Another boiler should not be fed from the same feed system, or propulsion plants cross connected, until the source of contamination has been found and isolated, since doing so would contaminate another boiler.

220-23.21 Types of Contamination.

The types of contamination include seawater, shore water, oil, demineralizer resin, silica gel, silica (from poor quality shore source feedwater), corrosion products, debris, and improper boiler chemical injection. The following description of the effects of various types of contamination should enable operators to identify the type of contamination:

1. **Seawater** contamination will cause the following effects in boiler water:
   a. Alkalinity decrease.
   b. Phosphate decrease.
   c. Conductivity increase.
   d. Chloride increase.
2. **Shore water** contamination will cause the following effects in boiler water:
   a. Alkalinity increase.
   b. Phosphate decrease.
   c. Conductivity increase.
   d. Chloride may increase, but not so severely as with seawater contamination.
3. **Oil** contamination of a boiler water sample will cause the following effects:
   a. Alkalinity unchanged.
   b. Phosphate unchanged.
   c. Conductivity may or may not be affected.
   d. Chloride may or may not be affected.

NOTE

Oil present in boiler water may carryover into the steam and condensate system and contaminate salinity/conductivity indicators and make them ineffective.

4. **Demineralizer Resin** which has passed into the boiler water will cause the following effects in boiler water:
   a. Alkalinity will normally decrease and may be difficult to maintain.
   b. Phosphate may increase or decrease.
   c. Conductivity increase.
   d. Chloride increase.
   e. The water may have an odor of dead fish.
5. **Desiccant** (silica gel) which was left in a boiler after dry layup will cause the following effect in boiler water:
   a. Phosphate may be higher than expected.
   b. Conductivity meter readings will be less than theoretical conductivity.
   c. Chloride is not affected.

NOTE

If these effects are noted, test boiler water for silica (see paragraph 220-26.33). Refer to paragraph 220-22.89 for limits and corrective action. Phosphate and alkalinity results are falsely high with silica present in boiler water.

6. **Silica from poor quality shore source feedwater** will cause the following effects in boiler water:
   a. Phosphate may be higher than expected.
   b. Conductivity meter readings will be less than theoretical conductivity.
   c. Chloride is not affected.

NOTE

> If these effects are noted, test boiler water for silica (see paragraph 220-26.33). Refer to paragraph 220-22.89 for limits and corrective action. Phosphate and alkalinity results are falsely high with silica present in boiler water.

7. **Bicarbonate** from shore source feedwater or shore steam condensate will cause the following effects in boiler water:
   a. Alkalinity will increase.
   b. Phosphate is not affected.
   c. Conductivity will increase.
   d. Chloride is not affected.

NOTE

> If these effects are noted, check feedwater for phosphate using the boiler water phosphate test. If phosphate is indicated to be greater than 5.0 ppm, the water is contaminated with bicarbonate and must be dumped.

8. **Excess Boiler Chemical Injection** or injection of the wrong material may cause any of the following effects in boiler water:
   a. Unexpected change in alkalinity.
   b. Unexpected change in phosphate.
   c. Rise in conductivity.
   d. Rise in chloride.
   e. Unusual appearance of water.
9. **Excess morpholine** after hydrazine/morpholine layup may cause any of the following effects in boiler water:
   a. Boiler water and desuperheater phosphate results will be falsely high.
   b. Conductivity meter readings will be less than theoretical conductivity.
   c. Boiler water conductivity measured by meter may show negligible increase.
   d. Boiler water chloride levels will not be affected.
   e. An ammonia-like odor may be present in samples.
10. **Corrosion** products will cause discoloration of the water and may cause changes in chemistry parameters.
11. **Debris** will cause abnormal appearance of the water and may cause changes in chemistry parameters.

220-23.22 Remove the Boiler Water Contamination.

This may be accomplished by blowdown or, if necessary, bottom blowdown, dumping, and flushing. Never blowdown a steaming boiler if blowdown would reduce alkalinity or phosphate below low limits, except in response to a high water casualty.

220-23.23

Surface blowdown will remove some of the dissolved contaminants and oil from a boiler. It is relatively ineffective in reducing high levels of dissolved contamination and sludge.

220-23.24

Bottom blowdown is effective in removing sludge from an idle boiler, and will also remove dissolved contaminants.

220-23.25 Sludge Removal and Inspection.

Serious boiler water contamination (as a result of seawater or shore water contamination), followed by proper chemical addition to restore alkalinity and phosphate will generate a large amount of sludge. This must be removed by bottom blowdown as soon as the boiler can be secured. If the boiler is to be dumped because of a chemical casualty, bottom blowdown before dumping is still required. During the next upkeep or repair period following a serious contamination incident, boiler watersides should be opened for inspection to determine if cleaning is necessary. If boiler water conductivity exceeds 2000 µmho/cm, superheater steamsides shall be flushed and inspected in accordance with **NSTM Chapter 221** prior to further operation. If boiler water conductivity exceeds 8000 µmho/cm, boiler watersides and superheater steamsides shall be flushed and inspected in accordance with **NSTM Chapter 221** prior to further operation. Consideration should be given to removing, splitting, and crimping a screen tube to determine the need for acid cleaning if the boiler was steamed under conditions of significant damage (alkalinity is 0 epm or phosphate is 0 ppm). Light-off may result in pH or phosphate below limits. Low pH or phosphate in the after on-the-line (AOL) sample is not moderate or serious contamination unless other symptoms are present. In the absence of other indications of contamination, this temporary condition does not warrant waterside inspection.

220-23.26 REPORTS.

The cognizant activity (for example, ship NAVSHIPYARD, SUPSHIP) shall provide a detailed message report within 24 hours to the Type Commander with an information copy to the ISIC, NAVSEA, and NSWCCD-SSES if any of the following conditions occur:

1. The contamination reaches a condition of significant damage as defined in paragraph 220-23.10.
2. The boiler is steamed under conditions of serious contamination for more than eight hours.
3. Any time the Commanding Officer does not reduce the steaming rate under conditions of serious contamination after one treatment action fails to correct boiler water parameters to moderate contamination or within limits.

220-23.27 REPORTS TO HIGHER AUTHORITIES

220-23.28

When the cognizant activity (Ship, NAVSHIPYARD, SUPSHIP) is requesting technical assistance or is reporting in accordance with paragraph 220-23.26, the following information shall be detailed in a report to the Type Commander with information copy to the ISIC, NAVSEA, and NSWCCD-SSES.

Boiler Water	Feedwater
1. Time (TIME).	1. Time (TIME).
2. Code (CODE).	2. Location (LOC).
3. Conductivity, µmho/cm (COND).	3. Salinity/conductivity reading (SI/CI).
4. Alkalinity, epm (ALK).	4. Chloride chemical test, epm (CL).
5. Phosphate, ppm (PHOS).	5. Hardness, epm (HARD).
6. Chloride, epm (CL).	6. Dissolved oxygen, ppb (DO).

Boiler Water	Feedwater
7. Boiler load, percent (LD).	7. Hydrazine, ppb (HYD).

Messages shall be formatted with the above information as follows:

For boiler water, read in seven columns:

TIME	CODE	COND	ALK	PHOS	CL	LD

For feedwater/condensate, read in seven columns:

TIME	LOC	SI/CI	CL	HARD	DO	HYD

The report shall include data for at least two samples taken prior to the contamination incident. For batch chemical additions (ADD), include ounces of TSP, DSP, or caustic soda injected.

220-23.29 STEAMING HOUR INSPECTIONS UNDER CHELANT TREATMENT.

Watersides shall be inspected as part of the 18 month boiler inspection unless one of the following conditions occurs:

1. Steaming without continuous treatment due to treatment system malfunction for more than 168 steaming hours (continuous), requires that the boiler watersides be inspected during the next upkeep or repair period.
2. Steaming with boiler water conditions that meet the criteria for significant damage, requires that the boiler watersides be inspected during the next upkeep or repair period. If conductivity exceeds 8,000 µmho/cm then waterside inspection shall be conducted prior to further operations. If conductivity exceeds 2,000 µmho/cm then superheater steamsides shall be flushed and inspected prior to further operations.

220-23.30 UNUSUAL CONTAMINATION.

If unusual contamination occurs, or if contamination cannot be identified, it is good engineering practice to collect samples. NSWCCD-SSES can provide analytical support in defining contaminant sources. Ship may forward samples of boiler water, feedwater, or deposits from tubes or drums for analysis to Carderock Division Naval Surface Warfare Center, Code 622, Philadelphia, PA 19112-5083. The following guidelines apply when forwarding samples:

Samples should be in plastic bottles labeled with ship name, boiler or plant number, sample location, date and time of sample. The following information should be sent with the sample:

1. Shipboard analysis results for the sample.
2. Boiler water chemistry test results after contamination occurred or was discovered.
3. Boiler water and/or feedwater logs, if appropriate.
4. Summary of any corrective action taken.
5. Results of follow-up inspections, if any.

220-23.31

Forward water samples in a tightly capped plastic bottle sealed with tape (1 quart minimum). About 1/8 ounce of deposit removed from tubes or drums is needed to perform an analysis. Copies of correspondence shall be forwarded to NAVSEA and to the Type Commander.

220-23.32 MODERATE CONTAMINATION OF BOILER WATER

220-23.33 DESCRIPTION.

Contamination of boiler water that affects the chemistry, appearance, or odor of the boiler water, but not so severely as to be classed as serious contamination under the criteria given in paragraph 220-23.9, is termed moderate contamination. Damage is not likely to occur under these conditions, but this moderate contamination is still a problem. If alkalinity or phosphate is below normal limits, then there is very little protection against scale formation or corrosion from additional contamination. If conductivity is high, or if chloride is above 1.0 epm, there is less room for additional contamination to occur without causing carryover. Slight carryover may cause damage to stainless steel superheater tubes because of chloride present in the boiler water. Abnormal appearance or odor indicates a problem that could cause damage if left alone, and also indicates that something is wrong in the plant; in addition, abnormal color will interfere with seeing color changes during the chemical tests. Return alkalinity and phosphate within normal limits by injecting treatment chemicals as appropriate. Sample 60 to 90 minutes later and re-treat as needed. Remove the contamination by blowdown. Alkalinity and phosphate must be kept within normal limits by chemical injection as necessary as long as the boiler is steaming. Concurrently, the source of contamination must be found and isolated.

220-23.34 WATER CONTROL PROBLEMS: SYMPTOMS AND ACTION

220-23.35 CARRYOVER OF BOILER WATER WITH STEAM.

Carryover is a very serious problem because it causes damage to the superheater, turbines, and other steam plant components. Damage from carryover is both mechanical and chemical. Mechanical damage is a result of high velocity water droplets striking and eroding superheater tubes, headers, piping valves, and turbine blading. Chemical damage comes from the boiler water contaminants and treatment chemicals, carried over with the water, depositing on the possibly attacking metal surfaces. For example, boiler water chloride carried over into a stainless steel superheater can cause chloride stress corrosion of the stainless steel. Carryover can be caused by mechanical problems, such as improperly installed steam separators or other steam drum internals, or high boiler water level. Carryover can also be caused by contamination of the boiler water with oily material and seawater, shore water, or other material that causes the conductivity of the water to be high.

220-23.36 Symptoms.

Loss of boiler water alkalinity, phosphate, conductivity, and chloride (with no blowdown being performed and no desuperheater leakage) indicates carryover or boiler water leakage. If one boiler is losing chemicals, requiring frequent treatment, while another fed from the same feed system is gaining chemicals or requires no treatment, either carryover or desuperheater leakage may be occurring. During operation, erratic fluctuations in superheater temperature are probably due to carryover, particularly if the boiler is at steady load. Foamy appearance of the water in the boiler gauge glass indicates carryover is probably occurring. If boiler water samples contain oil or scum, or have a conductivity in excess of limits, carryover should be suspected. If the conductivity of the sample exceeds 2,000 µmho/cm, it should be assumed that carryover is occurring. Large amounts of carryover will cause audible banging and rumbling in steam lines and turbines. Moderate carryover continuing for an extended period will cause a gradual rise in the salinity of steam drains and condensate. Steam drains and condensate should be analyzed for phosphate content; phosphate under chelant treatment with more than 10 ppm is a positive indicator of carryover, if there is no desuperheater leakage. Phosphate is determined by using the boiler water phosphate test. EDTA breakdown products may interfere with the phosphate test result, which is why phosphate must be greater than 10 ppm to indicate carryover or leakage. Morpholine from recent hydrazine layup will also interfere in this test. Carryover will be revealed, upon inspection, by chemical deposits in the superheater, on steam valves, and on turbine blading.

220-23.37 Action.

If carryover is occurring, the boiler must be secured to minimize damage, unless the Commanding Officer directs continued operation because of the operational situation. If operation must be continued, the firing rate should be minimized, and the boiler secured as soon as the operational situation allows. If must also be determined whether the cause is a mechanical problem or contamination of the water. If boiler water conductivity is within limits and the water is not oily, scummy, or otherwise abnormal, then the cause of carryover is mechanical and must be dealt with in accordance with **NSTM Chapter 221, Boilers.** If the conductivity is high, or oil, scum or other abnormal condition is present, or if foaming is visible in the boiler gauge glass, then the cause is contamination of the water. If the cause of carrryover is contamination, then blowdowns should be performed to reduce the contamination, injecting chemicals as necessary between blowdowns to keep alkalinity and phosphate within limits. Surface blowdown will usually be effective at removing oil contamination, especially if the steaming rate is low and the boiler water level is lowered to the surface blow line. If the boiler is secured, and carryover was due to high conductivity, dumping, flushing, and refilling will be the most effective method of eliminating the problem. The superheater of a boiler that has experienced carryover (for example, boiler water conductivity exceeds 2,000 µmho/cm) shall be flushed with hot feedwater and inspected prior to further operation in accordance with the procedures given in **NSTM Chapter 221** .

220-23.38 DESUPERHEATER LEAKAGE.

Desuperheater leakage allows boiler water, with contaminants and treatment chemicals, to enter the auxiliary steam systems. This causes deposits of boiler water contaminants and chemicals on valves, orifices, auxiliary turbines, and other desuperheater steam system components. These deposits can prevent components from operating properly, and can cause corrosion. In addition, the boiler treatment chemicals disappear from the boiler necessitating chemical addition. Salinity of drains and of condensate from auxiliary steam systems will be increased by the boiler water contaminants and treatment chemicals, making detection of seawater or other external contamination more difficult.

220-23.39 Symptoms.

Loss of boiler water alkalinity, phosphate, conductivity, and chloride (with no blowdown being performed and no carryover taking place) indicates leakage of boiler water out of the boiler, possibly into the desuperheater. If one boiler is losing chemicals, requiring frequent treatment, while another fed from the same feed system is gaining chemicals or requires no treatment, either carryover or desuperheater leakage may be occurring. If an unusual rise in superheater outlet temperature occurs, or erratic fluctuations in desuperheater outlet temperature occur with the boiler at steady load and with superheater outlet temperature steady, probable desuperheater leakage is indicated. High salinity of auxiliary steam drains may indicate desuperheater leakage. Buildup of chemical deposits on desuperheated system valve and turbine packing glands is a positive indication of desuperheater leakage if boiler water carryover is not occurring. The presence of boiler chemicals (phosphate more than 10 ppm) in condensate from the desuperheater steam is also a positive indication of desuperheater leakage if carryover is not occurring. (Phosphate in condensate is determined by using the boiler water phosphate test.) Morpholine from recent hydrazine layup will interfere in this test.

220-23.40 Action.

Desuperheater leakage can be corrected only by opening the boiler and repairing the desuperheater as discussed in **NSTM Chapter 221** , and in the specific boiler technical manual or boiler repair manual. A boiler with a leaking desuperheater should not be operated unless necessary because damage to components supplied with desuperheater steam will eventually result. If the boiler must be steamed, then boiler water must be sampled and treated frequently to keep alkalinity and phosphate within normal limits.

220-23.41 BOILER WATER LEAKAGE.

Boiler water can leak out of the boiler at rolled tube-to- tube sheet or tube-to-header joints, at handholes or manholes, through the blowdown system, the sampling system, the chemical injection system, the desuperheater, and through leaks in tubes and other pressure parts. The effect of this leakage on boiler water chemistry is the same as the effect of blowdown: conductivity, chloride, phosphate, and alkalinity all decrease.

220-23.42 Symptoms.

Excessive feedwater consumption or a continuous decrease in boiler water conductivity, chloride, phosphate, and alkalinity when no blowdowns or chemical injections are performed indicates either carryover or boiler water leakage. If carryover is not occurring, then leakage is. Excessive continuous blowdown flow will cause symptoms similar to boiler leakage. Ensure the blowdown rate is properly adjusted. Carryover and desuperheater leakage can be identified as discussed in paragraphs 220-23.35 and 220-23.38. Other leakage can be found by examining each piping system connected to the boiler and by inspection of those handhole and manhole openings and boiler fittings that are accessible. Steam or water coming from any piping system or fitting suspected of boiler water leakage can be tested for phosphate using the boiler water phosphate test. For ships with chelant treatment, a phosphate result of more than 10 ppm is an indication of leakage. Buildup of chemical deposits at valves and fittings indicates leakage.

220-23.43 Action.

A leaking boiler should not be operated unless necessary, because by themselves leaks always get worse, and the leak makes boiler chemistry control more difficult. If the boiler must be operated, boiler water must be sampled and treated more frequently to keep alkalinity and phosphate within normal limits.

220-23.44 CHEMICAL HIDEOUT CAUSED BY CONCENTRATION OF CHEMICALS.

This form of chemical hideout refers to the decrease or disappearance of boiler water phosphate and alkalinity not due to contamination, leakage or carryover. Hideout makes control of boiler water chemistry more difficult, and it is usually a symptom of dirty watersides. In a boiler experiencing hideout caused by chemical concentration, phosphate and alkalinity usually decrease when the boiler is operating at high power, necessitating frequent sampling and chemical injection to keep alkalinity and phosphate above low limits. When the boiler is returned frequent blowdown to keep conductivity from exceeding its high limit. Chemical concentration usually occurs because of porous deposits on boiler watersides. At high firing rates, the boiler chemicals concentrate in the deposits therefore taking those chemicals out of solution in the bulk of the boiler water. When firing rate is reduced, the concentration of boiler chemicals in the deposits decreases, so some of the chemicals that precipitated in the deposits at high firing rate redissolve and reappear in the bulk of the boiler water. This drives alkalinity, phosphate, and conductivity of samples up, necessitating blowdown to keep them in limits. Hideout may also be due to anything that causes relative stagnation of water in small area of the boiler. Crevices, pits, sharp bends in tubes, and the like, can cause local stagnation of the boiler water. Chemicals may concentrate in these stagnant areas, particularly if steam generation takes place in them.

220-23.45 Symptoms.

Decrease in boiler water phosphate and alkalinity may be caused by hideout. If no blowdowns are being performed, contamination is not occurring, leakage is not occurring, and carryover is not occurring, then hideout is likely. If hideout caused by chemicals concentrating is suspected, conduct the following test:

1. Within 90 minutes before securing the boiler, sample and test the boiler water. Do not treat the boiler water prior to securing.

2. Secure the boiler and allow it to remain secured for 2 hours without blowdown. Continue to feed the boiler as required to maintain normal boiler water level.

3. Retest the boiler water.

If the boiler water results are at least double the value obtained before securing the boiler, severe hideout is occurring. Any increase in phosphate after securing is an indication that hideout may be occurring.

220-23.46 Action.

If hideout is occurring, notify the Type Commander and send an information copy to ISIC, NAVSEA, and NSWCCD-SSES. A boiler experiencing severe concentration of chemicals should not be operated unless necessary because of the difficulty of keeping alkalinity, phosphate, and conductivity within normal limits. If the boiler must be operated, then it must be sampled and treated or blow down frequently to keep alkalinity and phosphate above low limits and conductivity below its limit. Hideout due to waterside deposits can be corrected only by cleaning watersides. Water-jet cleaning is usually effective. Mechanical tube punching is of less value. If hideout remains after water-jet cleaning, consider chemical cleaning and ensure that water-jet cleaning is accomplished after the chemical cleaning.

220-23.47 BOILER CHEMISTRY PROBLEMS ON PLANT STARTUP.

Difficulties with plant chemistry control often occur during the initial period of operation following a prolonged shutdown period, especially if boilers were chemically cleaned, or extensive plant repair work was conducted. Frequent sampling and treatment of boiler water will be required to keep boiler water chemistry in limits and to remove suspended matter, discoloration and other abnormalities. Abnormal changes or conditions in boiler water should not be cause for alarm during this initial period unless alkalinity, phosphate, and conductivity cannot be kept in limits or the abnormal conditions do not clear up within 5 operating days. If boiler water is too dirty to detect indicator color changes, secure the boiler, bottom blow, dump, flush systems that may contain the source of contamination, and begin again.

220-23.48 SEAWATER CONTAMINATION OF FEEDWATER.

Feedwater that is contaminated with seawater will cause seawater contamination of the boiler water. If it does occur, prompt action must be taken to prevent boiler damage. Concurrently, the source of seawater contamination must be found, isolated, and corrected so that normal plant operation can be resumed. Sources of seawater contamination include condenser leakage, bilge water drawn into condensate pumps and condensate piping in the bilge, contamination makeup feed, contamination of evaporator drains, contaminated drains from service steam systems, and unauthorized steam or steam drain system connections to seawater systems or hull connections.

220-23.49 Symptoms.

Salinity/conductivity indicators are installed to monitor various points in the feedwater and condensate systems and in the distilling plants. Salinity/conductivity indicators in the feedwater and condensate systems provide a means for detecting and identifying the source of contamination in the boiler feedwater. However, in many Navy ships, alarms are not installed on feedwater and condensate system salinity/conductivity indicators; therefore, momentary shots of contamination and their sources are unlikely to be detected or identified before they enter the boiler. Ships that have alarms on all salinity/conductivity indicators in the feedwater and condensate systems are able to immediately detect and identify the source of such shots of contamination. Feedwater, condensate, or drains, which contain low level of contamination, but below limits, can cause serious boiler water contamination in a matter of hours. This will be especially true if the plant is steaming at a moderate to high rate. All installed salinity/conductivity indicators must be frequently monitored by plant watch standers, and any reading above normal must be reported on the EOOW and the Oil King. When an abnormally high salinity/conductivity reading occurs, boilers being fed from the affected system should be immediately tested and appropriate chemistry casualty control action taken. It should always be suspected that contamination has occurred if bilge water gets high enough to cover any part of the condensate system or low-pressure steam drain system, or a reserve feed tank manhole. Bilges should be pumped to keep such high levels from occurring, and if such high bilge level does occur, salinity/conductivity indicators should be immediately checked and boiler water sampled and analyzed for contamination. Boiler water must be sampled frequently whenever feedwater contamination is known or suspected in order to maintain control of boiler chemistry.

NOTE

Low-level seawater or shorewater contamination can exceed the available EDTA, resulting in sludge formation. Boiler waterside cleaning could then be required. Symptoms of low-level contamination are increased frequency of surface blowdown or batch treatment (i.e., required more often than every 72 hours). Proper operation and monitoring of feedwater salinity or conductivity indicators is essential to prevent and detect low-level contamination. Notify the Type Commander, with information copy to ISIC, NAVSEA, and NSWCCD-SSES if surface blowdowns are required more frequently than every 72 steaming hours. Blowdown frequency is calculated at the end of each month as part of the monthly boiler water package. The steam hours for one month are divided by the number of surface blowdowns performed in that month, except when boiler steaming hours are less than 200. Scum blowdowns are blowdowns needed to control specific instances of contamination that are corrected within 72 hours are not included in the calculation.

220-23.50 Action.

The source of contamination must be found and isolated. At the same time, boilers being fed from the contaminated system must be sampled, and action taken to control boiler water chemistry.

220-23.51 Locating the Source of Contamination.

Salinity/conductivity cells may indicate the source of contamination directly. However, continuous contamination of less than 0.02 epm chloride, or contamination of an intermittent nature will be harder to find. Intermittent contamination is usually due either to bilge water, service steam drains or makeup feed. Bilges should be pumped dry to eliminate that possible source. Makeup feed can be sampled and analyzed chemically for chloride contamination. Steam drains can be dumped to the bilge. Samples of steam drain condensate can be collected from various locations starting with the freshwater (or low-pressure) drain collecting tank, cooled to less than 37.8°C (100°F) and analyzed for chloride. After the bilges are pumped down, and drains and makeup feed are proven free of contamination or diverted to the bilge, then the water sample analysis indicates contamination is still occurring, it is most likely caused by a condenser leak. It may be difficult to detect a condenser leak by the chloride test because the chloride concentration may be low due to high condensate flow through the condenser. Prior to sampling main condenser condensate, it is preferable to reduce the steam/condensate flow through the condenser as much as possible (that is, slow the main engine). This has the effect of increasing chloride concentration by lowering condensate flow (due to lower steam flow) and increasing any seawater leakage which may be occurring by increasing condenser vacuum. Any leakage should concentrate enough to be detectable by the feedwater chloride test in a few minutes. Condensate flow rates from auxiliary condensers, drains and makeup feed are so low that significant contamination should be detectable without additional concentration.

220-23.52 SHORE WATER CONTAMINATION OF FEEDWATER.

Shore water differs from seawater in that total dissolved solids are lower, but the proportion of calcium hardness and silica in relation to chloride is much higher. Salinity/conductivity indicators are less effective at warning of shore water contamination than seawater contamination. It is likely that the first indication of shore water contamination will be in boiler water samples, which will show a drop in phosphate, an increase in alkalinity and conductivity, with little change in chloride concentration. The source of shore water contamination must be found and isolated promptly.

220-23.53 Symptoms.

Shore water contamination of the boiler water indicates that the feedwater is contaminated with shore water. Hardness which is approximately equal to or greater than chloride in a feedwater sample indicates shore water contamination. It will most likely come from service steam drains or makeup feed. Low-level contamination may occur with symptoms as described in the note for seawater contamination, paragraph 220-23.49.

220-23.54 Action.

If shore water contamination is occurring, find the source of the contamination by sampling the several possible points at which contamination could occur and analyzing for hardness, chloride and bicarbonate. Shore water contamination is usually caused by one of the following:

1. Leaking hot water heater coils when shore source potable water is in use and shipboard auxiliary steam is secured.
2. Leaking or missing check valves in direct contact type hot water heating piping while using shore source potable water.
3. Improper valve lineup or leaking/failed valves in feedwater/potable water system while taking on shore source potable water.

NOTE

> Direct contact type steam heaters are not authorized for use in Navy ships and must be replaced whenever identified.

Shore source potable water can contaminate shipboard steam heating drain systems and result in deposits which cause contaminated steam drains for several days or more after shipboard steaming is resumed. When the source of the contamination is found, isolate and dump the contaminated water and repair equipment. Meanwhile, test the boiler water for contamination, and if present, take action. If contamination persists after equipment repair, inspect hotel drain piping for evidence of deposits.

220-23.55 OIL CONTAMINATION OF FEEDWATER.

Oil contamination of feedwater may occur from several sources. These are as follows:

1. Leakage of lubricating oil from bearings into turbine glands, and then into the low-pressure drain system.
2. Leakage of oil into the steam in the lubricating oil purifier heater.
3. Leakage of oil into the steam heating coils in lubricating oil settling tanks.
4. Leakage of fuel oil into the steam side of fuel oil heaters if installed.

5. Leakage of fuel oil into a reserve feed tank through a hole in the bulkhead between adjacent tanks or through an improper piping lineup.
6. Spillage of oil into LP steam drain funnels.
7. Contamination of service steam drains from somewhere outside the propulsion plant.
8. Preservative or oil from steam plant components that were installed without proper cleaning.
9. Oily bilge water being drawn into condensate pumps or piping.
10. Oily bilge water leaking into double bottom reserve feed tanks.
11. Leakage of fuel oil into atomizing steam lines.

220-23.56 Symptoms.

Oil in the boiler water sample or gauge glass indicates possible feedwater contamination with oil.

220-23.57 Action.

Find the source of oil contamination by examining water samples from all possible sources of oil and checking for visible oil or oily odor. Once the source is found, isolate and repair. Oil contamination in boiler water volatilizes and carries over with the steam into the steam and condensate system and coats condensate system salinity/conductivity probes, negating their effectiveness. If oil contamination is observed, check salinity/conductivity indicators for proper operation by chemical comparison test and clean probes, if necessary.

220-23.58 OXYGEN CONTAMINATION OF FEEDWATER.

Oxygen contamination of feedwater will cause dissolved oxygen attack of boiler tube metal.

220-23.59 Symptoms.

Dissolved oxygen concentration in feedwater, above 15 ppb indicates DFT malfunction.

220-23.60 Action.

Excess dissolved oxygen in the feedwater will cause boiler damage. The cause should be found and corrected as soon as possible. Boilers should be secured or operations minimized until the cause of the high dissolved oxygen is corrected. Possible causes are:

1. Improper operation of the DFT spray valves or steam atomizing valve.
2. Inadequate venting of the DFT.
3. Excessive water level in the DFT, flooding the steam atomizing valve.
4. DFT shell pressure higher than auxiliary exhaust pressure. This can be a temporary effect of large maneuvering transients, or a continuous effect of excess HP drain pressure in those ships where HP drains are piped directly to the shell of the DFT.
5. Inadequate recirculation and warmup of the DFT during plant startup.
6. Fluctuating auxiliary exhaust pressure as a result of a malfunction of the augmenting or unloading valve, malfunction of DFT level controls, or from erratic operation of steam driven auxiliaries.

7. A large shot of condensate that causes a sharp drop in DFT shell pressure, because of improper operation of a condensate pump, or sudden opening of the condensate cross connect valve or DFT condensate inlet valve.

220-23.61 EXCESSIVE CHELANT TREATMENT.

Overtreatment with chelant treatment chemicals (hydrazine, EDTA, and di/trisodium phosphate) can occur due to continuous treatment system malfunction, misalignment of system valves, or insufficient continuous blowdown.

220-23.62 Symptoms.

Overtreatment will be indicated by an increase in the salinity/conductivity indicators, first at the DFT then throughout the plant as the breakdown products volatilize from the boiler. Comparison test results will show the indicator reading to be greater than the chemical test result. The continuous treatment tank level will decrease more than expected. Feed water hydrazine will exceed 40 ppb. Excessive chelant treatment solution will cause boiler water alkalinity, phosphate, and conductivity to increase.

220-23.63 Action.

If boiler water chemical levels exceed upper limits, conduct blowdown as required. The salinity/conductivity indicator readings will return to normal with steaming. Avoid excessive chelant treatment in order to prevent corrosion of boiler watersides by EDTA or corrosion of preboiler system copper alloys by ammonia from hydrazine decomposition. Table 220-22-6 provides guidance for correcting problems that may develop from a malfunction in the continuous injection system or continuous blowdown system. Corrective actions are listed opposite the possible causes for each problem.

220-23.64 EXCESSIVE MORPHOLINE.

Morpholine will be present in boiler water following hydrazine/morpholine layup.

220-23.65 Symptoms.

High levels of morpholine will cause the boiler water phosphate test to give false high results. The presence of high levels of morpholine is confirmed by the theoretical conductivity (paragraph 220-22.49) being significantly greater than the measured conductivity.

220-23.66 Action.

Blowdown or dumping of the boiler is not required to reduce the indicated high phosphate. Sample the steaming boiler every 4 hours until test results return to normal. If it is necessary to treat for low alkalinity, batch inject caustic soda in accordance with Table 220-22-9. Following light-off, the morpholine will volatilize from the boiler with the steam and may cause the salinity/conductivity indicator readings to be higher than the chemical chloride test results. Use of feedwater and condensate shall be based on the chemical chloride test result. On the logs, circle any result that is above limits due to high morpholine levels and explain in remarks. This temporary condition does not cause damage to the plant and is not considered to be contamination. Hours steamed with high levels of morpholine are not counted as hours steamed with contamination. High levels of morpholine will usually dissipate within 24 steaming hours.

NOTE

The symptoms of silica contamination can be similar to those of excessive morpholine. If silica contamination is suspected, test the boiler water for silica in accordance with paragraph 220-26.33. Refer to paragraphs 220-22.79 through 220-22.92 for guidance on silica contamination.

220-23.67 SODIUM NITRITE CONTAMINATION.

Sodium nitrite is used for wet layup of idle boilers. Sodium nitrite is not to be used by ship's force on chelant treatment ships for layup, waterjet cleaning, or hydrostatic testing due to incompatibility with hydrazine. It may be used during an industrial availability or overhaul. Sodium nitrite contamination is due to insufficient flushing of the boiler and associated DFT and feedwater piping following sodium nitrite layup, hydrostatic testing with sodium nitrite treated water, or leakage of the layup or hydrostatic test solutions into the steam or drain systems. The boiler and all feedwater components exposed to sodium nitrite must be flushed prior to feeding the boiler for light-off. Sodium nitrite contamination will affect boiler water/feedwater test results in a steaming boiler as follows:

1. Feedwater chloride will be falsely high and end point may be difficult to detect.
2. Feedwater salinity/conductivity will increase.
3. Boiler water alkalinity will increase.
4. Boiler water conductivity will increase.
5. Chloride test results for a steaming boiler are not usually affected. However, upon boiler light-off chloride results for after on-line sample may be falsely high until nitrite has dissipated.

Sodium nitrite contamination is corrected by using the appropriate casualty control procedures based on test results.

220-23.68 OTHER FEEDWATER CONTAMINATION.

Some contaminants in the feedwater other than those discussed above will probably cause abnormal chemical behavior, appearance, or odor in the boiler water in the feedwater. The source of this contamination must be found, isolated, and corrected, while taking action to control boiler chemistry.

220-23.69

Some examples of other contamination include:

1. Dirt or debris.
2. Corrosion products.
3. Demineralizer resin.
4. Desiccant.
5. Silica and bicarbonate from poor quality shore source feedwater.

220-23.70 CASUALTY CONTROL PROCEDURES

220-23.71 INDIVIDUAL SHIP PROCEDURES.

Individual ship casualty control procedures shall conform to the procedures given below. For explanation, refer to the principles of plant chemistry casualty control earlier in this section.

220-23.72 PROCEDURE OUTLINES.

The next several paragraphs outline casualty procedures for several plant chemistry casualties. These are as follows:

1. Serious contamination of boiler water.
2. Moderate contamination of boiler water.
3. Boiler water carryover.
4. Leakage of boiler water.
5. Seawater contamination of feedwater.
6. Shore water contamination of feedwater.
7. Oil contamination of feedwater.
8. High dissolved oxygen in feedwater.
9. Sodium nitrite contamination of boiler water.
10. Other contamination of feedwater.

220-23.73

For each casualty, a reference is given to the paragraph of this section that provides a complete description of the casualty, abbreviated lists of symptoms and possible causes are given, and step-by-step plant corrective actions are outlined. The actions are broken down into Immediate Actions must be taken promptly. The EOOW and other watch standers must refer to the procedure to verify that Immediate Actions are complete, and then proceed with the Follow-up Actions to make the plant ready to resume normal operations.

220-23.74 PROCEDURE OUTLINE: SERIOUS CONTAMINATION OF BOILER WATER.

Reference paragraphs 220-23.8 through 220-23.26.

1. **Symptoms.** Any of the following conditions indicates serious contamination of the boiler water:
   a. Alkalinity greater than 1.500 epm.
   b. Alkalinity less than 0.050 epm.
   c. Phosphate less than 5 ppm.
   d. Conductivity more than 1,500 µmho/cm.
   e. Dissolved oxygen in the feedwater entering the boiler is greater than 15 ppb for more than 4 hours after detection. (Refer to paragraph 220-23.82.)
2. **Possible causes:**
   a. Seawater contamination of the feedwater.

b. Shore water contamination of the feedwater.
c. Oil contamination of the feedwater.
d. Demineralizer resin in the feedwater.
e. Dirt, debris, corrosion products or other contamination of the feedwater.
f. Injection of wrong, contaminated or excessive chemicals into the boiler.
g. Improper alignment of DFT.
h. Insufficient continuous blowdown.

3. **Immediate Actions:**
   a. Test and treat in accordance with paragraph 220-23.12.
   b. If one treatment action does not return the boiler to a condition of moderate contamination or within limits, secure the boiler unless the Commanding Officer directs continued operation. If operation must be continued, minimize the firing rate until boiler water chemistry is within limits and the source of the contamination is isolated or corrected.
   c. Initiate action to identify the type and source of contamination. Take corrective action in accordance with the appropriate procedure for feedwater contamination.

4. **Follow-up Actions:**
   a. Continue to sample the boiler water frequently until conditions are returned to normal.
   b. Inject chemicals as necessary to keep alkalinity and phosphate within normal limits as long as the boiler is steaming.
   c. Carry out the procedure for carryover of boiler water, paragraph 220-23.37, if boiler water conductivity exceeds 2,000 μmho/cm, if oil or foaming are visible in the water, or if carryover is known to be occurring.
   d. Carry out the procedure for damage to a boiler pressure part as discussed in **NSTM Chapter 079 Volume 3, Damage Control - Engineering Casualty Control** , if a boiler tube or other pressure part ruptures.
   e. Perform surface blowdowns to reduce conductivity if the boiler is steaming, and to remove oil contamination. However, alkalinity and phosphate must be kept within normal limits by chemical injection as necessary.
   f. Secure the boiler as soon as possible and perform bottom blowdowns to remove sludge.
   g. Blowdown or dump the boiler to reduce contamination (conductivity or oil) to normal limits.
   h. Find and isolate the source of contamination. Once the source has been isolated, other boilers may be fed from that feed system if desired. Refer to the appropriate procedure for feedwater contamination, paragraphs 220-23.78 through 220-23.84.

220-23.75 Procedure Outline: MODERATE CONTAMINATION OF BOILER WATER.

Reference paragraph 220-23.32.

1. **Symptoms:**
   a. Boiler water alkalinity, phosphate, or conductivity changing unexpectedly or out of limits, but not severely enough to be classified as serious contamination.
   b. Presence of suspended solids, abnormal color, or odor in boiler water.

2. **Possible Causes:**
   a. Moderate contamination of feedwater.

b. Moderate amounts of debris, corrosion products, or preservatives following a repair period.

3. **Immediate Action:**

   a. Sample and treat boiler water as necessary to keep alkalinity and phosphate in limits.

4. **Follow-up Actions:**

   a. Conduct blowdowns to remove contamination. Keep alkalinity and phosphate in limits as long as the boiler is steaming.

   b. Find, isolate, and correct the source of contamination.

   c. If symptoms of major contamination appear, take action in accordance with the procedure for serious boiler water contamination outlined in paragraph 220-23.74.

220-23.76 Procedure Outline: BOILER WATER CARRYOVER.

Reference paragraph 220-23.35.

1. **Symptoms:**

   a. Visible foaming in boiler gauge glass.

   b. Erratic fluctuation of superheater outlet temperature.

   c. Audible rumbling or banging in steam lines.

   d. Boiler water conductivity greater than 2,000 µmho/cm.

   e. Detectable phosphate in condensate or drains.

   f. Visible buildup of chemical residue on steam drains, valves stems, and other fittings in superheated steam system.

2. **Possible Causes:**

   a. High boiler water level.

   b. Improper installation or malfunction of steam drum internals.

   c. Oil in the boiler water.

   d. Boiler water conductivity in excess of limits.

   e. Excessive suspended solids in boiler water.

3. **Immediate Actions:**

   a. Secure the boiler unless the Commanding Officer directs continued operation. If operation must be continued, minimize the firing rate.

   b. Determine if boiler water level is high, if conductivity is above limits, or if oil contamination exists.

   c. Perform surface blowdown if the boiler is still steaming. Keep alkalinity and phosphate in limits.

4. **Follow-up Actions:**

   a. If boiler water is contaminated, carry out the appropriate procedure for contamination of boiler water:

      (1) Serious contamination of boiler water, paragraph 220-23.74.

      (2) Moderate contamination of boiler water, paragraph 220-23.75.

   b. If boiler water level is high, carry out the procedure for boiler water high level in **NSTM Chapter 079 Volume 3, Damage Control - Engineering Casualty Control** , if installed.

   c. If boiler water is not contaminated and water level is not high but carryover is continuing, the cause is probably due to improper functioning of steam drum internals. The internals must be inspected and repaired in accordance with **NSTM Chapter 221** , the specific Boiler Technical Manual, and the Boiler Repair Manual.

d. Flush the superheater with feedwater. Inspect superheater steamsides and steam drum internals and clean as necessary. Refer to the procedure given in **NSTM Chapter 221** .

220-23.77 Procedure Outline: LEAKAGE OF BOILER WATER.

Reference paragraphs 220-23.38 and 220-23.41.

1. **Symptoms:**
   a. Drop in boiler water conductivity, chloride, alkalinity, and phosphate not due to blowdown or carryover.
   b. Erratic or abnormally low desuperheater outlet temperature with normal superheater outlet temperature.
   c. Unusual rise in superheater outlet temperature.
   d. Visible buildup of chemical residue at drains, valve stems, and other fittings in desuperheated steam system.
   e. Presence of boiler chemicals in desuperheated steam samples.
   f. Visible leakage from boiler handhole, manhole, or other fitting.
   g. Blowdown piping hot and pressurized with no blowdown being conducted.
   h. Abnormally high consumption of reserve feed.
2. **Possible Causes:**
   a. Leaking desuperheater.
   b. Leaking valve, tube, handhole, manhole, or other fitting that is a boiler water pressure boundary.
   c. Excessive continuous blowdown.
3. **Immediate Actions:**
   a. Inject chemicals as necessary to keep alkalinity and phosphate in limits until the boiler is secured.
   b. Secure the boiler.
   c. Establish proper continuous flowrate.
4. **Follow-up Actions:**
   a. If a rupture tube has occurred, carry out the procedure for ruptured boiler tube in **NSTM Chapter 079 Volume 3, Damage Control - Engineering Casualty Control** .
   b. As long as the boiler is steaming, keep alkalinity and phosphate within normal limits by chemical injection as necessary.
   c. Find and repair the leak as soon as possible as discussed in paragraphs 220-23.38 and 220-23.41, in **NSTM Chapter 221** , in the specific Boiler Technical Manual, and in the Boiler Repair Manual.

220-23.78 Procedure Outline: SEAWATER CONTAMINATION OF FEEDWATER.

Reference paragraph 220-23.48.

1. **Symptoms:**
   a. Contamination of boiler water with seawater.
   b. Salinity/conductivity reading above normal on feed and condensate system salinity/conductivity indicators.

c. Salinity/conductivity alarm (if installed) on feed and condensate system salinity/conductivity indicators.
d. Chloride or hardness above limit by chemical test in reserve feed, condensate, drains, or boiler feedwater.

2. **Possible Causes:**
   a. Contaminated steam drains.
   b. Bilge water drawn into condensate pump or piping.
   c. Condenser tube leak.
   d. Contaminated makeup feed.
   e. Evaporator feed heater leakage or brine carryover to air injectors.

3. **Immediate Action:**
   a. Sample the steaming boilers. Carry out procedure in paragraph 220-23.74 or 220-23.75, as appropriate.

4. **Follow-up Actions:**
   a. Attempt to find the source of contamination by salinity/conductivity indicator and the chemical test for chloride.
   b. Continue to sample and treat steaming boilers as necessary to keep alkalinity and phosphate in limits.
   c. Once the source of contamination is found, isolate and repair.

5. Finding the Source of Contamination. Test the possible sources of seawater contamination for chloride. These would include the following as appropriate in the order given:
   a. Service steam drains and freshwater drains.
   b. Makeup feed.
   c. Evaporator feed heater and air ejector drains.
   d. Auxiliary gland exhaust condenser drains.
   e. Auxiliary condensate.
   f. Main condensate.

220-23.79

If salinity/conductivity readings or chemical test do not indicate the source of contamination, concentrate the samples as discussed in paragraph 220-23.51 and test again.

220-23.80 Procedure Outline: SHORE WATER CONTAMINATION OF FEEDWATER.

Reference paragraph 220-23.52.

1. **Symptoms:**
   a. Drop in boiler water phosphate with an increase in alkalinity. Conductivity and chloride may or may not change.
   b. High salinity/conductivity reading or alarm (if installed) on feed and condensate system salinity/conductivity indicators.
   c. High feedwater hardness test result.

2. **Possible Causes:**
   a. Shore source reserve feed.
   b. Contamination of ship's system with shore steam.

c. Leakage of shore potable water into ship's steam drains.

d. Distillation to reserve feed in a river or lake.

3. **Immediate Action:**

a. Sample steaming boiler(s) to determine extent of boiler water contamination. Carry out procedure in paragraph 220-23.74 or 220-23.75, as appropriate.

4. **Follow-up Actions:**

a. Attempt to find the source of contamination using salinity/conduct ivity indicators, and the chemical test for hardness.

b. Sample and treat the boiler as necessary to keep alkalinity and phosphate in limits.

c. Once the source of contamination is found, isolate and correct it.

220-23.81 Procedure Outline: OIL CONTAMINATION OF FEEDWATER.

Reference paragraph 220-23.55.

1. **Symptoms:**

a. Oil contamination of boiler water.

b. Visible oil or foaming in DFT sightglass.

c. Visible oil or oily odor in feedwater samples.

2. **Possible Causes:**

a. Lubricating oil leakage into turbine glands.

b. Oily bilge water drawn into condensate pumps, piping or steam drains.

c. Leakage of lubricating oil purifier heater, lubricating oil settling tank heating coils, fuel oil heaters or fuel oil tank heating coils (if installed).

3. **Immediate Actions:**

a. If oil is visible in gage glass, conduct surface blowdown and gage glass blowdown.

b. Check boiler water sample for oil contamination. If found, carry out the procedure in paragraph 220-23.74.

c. Ensure bilge water is low.

4. **Follow-up Action:**

a. Find the source of oil contamination by sampling throughout the feed and condensate system. Isolate and repair the source when found.

220-23.82 Procedure Outline: HIGH DISSOLVED OXYGEN IN FEEDWATER.

Reference paragraph 220-23.58.

1. **Symptom:**

a. Feedwater dissolved oxygen concentration greater than 15 ppb.

2. **Possible Causes:**

a. Auxiliary exhaust system not properly lined up to DFT.

b. Auxiliary exhaust system pressure low or unstable.

c. Excess HP drain pressure in ships that have HP drains piped directly to the DFT shell.

d. Malfunction of DFT condensate spray valves.
e. Malfunction of DFT steam atomizing valve.
f. DFT water level high enough to flood the atomizing valve.
g. Leak in shell and tube type vent condenser.
h. Improper venting of the DFT.
i. Large fluctuations in condensate flow, particularly if the auxiliary exhaust augmenting and unloading valves operate sluggishly or improperly.
j. Inadequate recirculation of feedwater during DFT warmup. (The effect of this will disappear within two hours after the plant is in full operation.)

3. **Immediate Action:**
   a. Ensure proper sampling procedures as used.
   b. Ensure the auxiliary exhaust system is properly lined up to the DFT, that auxiliary exhaust pressure is in the normal range, that the DFT water level is in the normal range, and that the DFT vent is properly lined up.

4. **Follow-up Actions:**
   a. If high dissolved oxygen cannot be corrected, minimize steaming rates until the plant can be secured.
   b. If dissolved oxygen is greater than 15 ppb for more than 8 hours, the boiler must be secured unless the Commanding Officer directs continued steaming. Securing will minimize boiler damage and permit DFT repair.

220-23.83 Procedure Outline: SODIUM NITRITE CONTAMINATION OF BOILER WATER.

1. **Symptoms:**
   a. Feedwater chloride will be falsely high and end point may be difficult to detect.
   b. Feedwater salinity/conductivity will increase.
   c. Boiler water alkalinity will increase.
   d. Boiler water conductivity will increase.
   e. Chloride test results for a steaming boiler are not usually affected.

2. **Possible Causes:**
   a. Insufficient flushing of boiler and associated DFT and feed piping following sodium nitrite layup or hydrostatic testing with sodium nitrite treated water.
   b. Leakage of sodium nitrite solution into steam drain system.

3. **Immediate Action:**
   a. Follow appropriate casualty control procedures based on test results.

NOTE

Sodium nitrite may be used only on chelant treated ships during an availability or overhaul.

220-23.84 Procedure Outline: OTHER CONTAMINATION OF FEEDWATER.

Reference paragraph 220-23.68.

1. **Symptoms:**
   a. Contamination of boiler water other than from seawater, shore water, or oil.
   b. Abnormal appearance, odor, salinity/conductivity, or other characteristics in feedwater.
2. **Possible Causes:**
   a. Depends on nature of contamination. May include the following:
      (1) Escape of resin from the demineralizer.
      (2) Dirt, debris, corrosion products, or preservative from piping or components.
      (3) Use of feedwater from an expended shore demineralizer.
3. **Immediate Action:**
   a. Sample the boiler(s) and carry out procedure in paragraph 220-23.74, or paragraph 220-23.75.
4. **Follow-up Action:**
   a. Attempt to locate the source of contamination. Isolate and correct the cause when found.

220-23.85 CASUALTY CONTROL GUIDE TABLE.

Table 220-23-1 is a casualty control guide. Symptoms are tabulated as abnormalities in boiler water, steam systems, feedwater, condensate, and drain systems. For each symptom, the casualty or casualties that may result are listed together with a casualty control procedure paragraph number. This guide is provided as a training aid and convenient reminder to plant supervisors and does not relieve supervisors of the need to be thoroughly familiar with the symptoms of casualties and the immediate corrective actions.

Table 220-23-1 CASUALTY CONTROL GUIDE

Symptoms	Casualty	Procedure Paragraph
1. Boiler Water		
a. Alkalinity greater than 1.500 epm	Serious contamination of boiler water	220-23.74
b. Alkalinity less than 0.050 epm	Serious contamination of boiler water	220-23.74
c. Phosphates less than 5 ppm	Serious contamination of boiler water	220-23.74
d. Conductivity more than 1,500 μmho/cm	1. Serious contamination of boiler water 2. Carryover of boiler water	220-23.74 220-23.76
e. Oil in the boiler water sample	1. Serious contamination of boiler water 2. Carryover of boiler water	220-23.74 220-23.76
f. Foaming or other evidence of boiler water carryover	1. Serious contamination of boiler water 2. Carryover of boiler water	220-23.74 220-23.76
g. Chemistry conditions out of control	Serious contamination of boiler water	220-23.74
h. Chemistry slightly out of limits	Moderate contamination of boiler water	220-23.75
i. Suspended solids, abnormal color or abnormal odor in boiler water	Moderate contamination of boiler water	220-23.75
j. Drop in conductivity, chloride, alkalinity, and phosphate	1. Excessive continuous blowdown 2. Carryover of boiler water 3. Leakage of boiler water 4. Chemical hideout	220-23.77 220-23.76 220-23.77 220-23.44

Table 220-23-1 CASUALTY CONTROL GUIDE - Continued

Symptoms	Casualty	Procedure Paragraph
k. Visible leakage from boiler fitting	Leakage of boiler water	220-23.77
2. STEAM SYSTEMS		
a. Erratic fluctuations of superheater outlet temperature	Carryover of boiler water	220-23.76
b. Audible rumbling or banging in steam lines	Carryover of boiler water	220-23.76
c. Buildup of chemical deposits on valve packing glands	1. Carryover of boiler water 2. Leakage of boiler water	220-23.76 220-23.77
d. Erratic or low desuperheater outlet temperature	Leakage of boiler water	220-23.77
3. FEEDWATER, CONDENSATE AND DRAINS		
a. Detectable phosphate	1. Carryover of boiler water 2. Leakage of boiler water 3. Test interference from morpholine/bicarbonate	220-23.76 220-23.77 220-23.76220-23.77
b. Abnormally high consumption of reserve feedwater	Leakage of boiler water	220-23.77
c. Salinity/conductivity reading above normal or salinity/conductivity alarm	1. Seawater contamination of feedwater 2. Shore water contamination of feedwater 3. Other contamination of feedwater	220-23.78 220-23.80 220-23.84
d. Chloride above limits	1. Seawater contamination of feedwater 2. Other contamination of feedwater 3. Shore water contamination of feedwater	220-23.78 220-23.84 220-23.80
e. Hardness above the limit	1. Shore water contamination of feedwater 2. Seawater contamination of feedwater 3. Other contamination of feedwater	220-23.80 220-23.78 220-23.84
f. Detectable oil	Oil contamination of feedwater	220-23.81
g. Foaming in DFT sightglass	1. Oil contamination of feedwater 2. Other contamination of feedwater	220-23.81 220-23.84
h. Dissolved oxygen in DFT sample greater than 15 ppb	High dissolved oxygen in feedwater	220-23.82
i. Abnormal appearance, odor or other characteristic of feedwater	Other contamination of feedwater	220-23.84

SECTION 24.

TECHNIQUES OF QUANTITATIVE ANALYSIS AND TROUBLESHOOTING

220-24.1 QUANTITATIVE ANALYSIS

220-24.2

Quantitative analysis is a branch of analytical chemistry that is concerned with the determination of the amounts of various materials in a sample. All feedwater and boiler water tests that result in a numerical value are governed by principles developed in this branch of chemistry. Decisions regarding treatment are based entirely on the numbers obtained by the Oil King who performs the feedwater and boiler water tests. It is important that the Oil King be familiar with the chemical techniques, tools, and test methods available so that accurate analyses can be made. When performing boiler water or feedwater tests, the Oil King shall use the procedures and techniques described in this section and in Section 26. The procedures shall be done in step-by-step compliance and not done from memory. The sample bottle should be recapped after the removal of each quantity of sample water for a specific test. Boiler water or feedwater testing should be conducted in the following sequence as applicable:

1. pH
2. Conductivity
3. Alkalinity
4. Phosphate
5. Chloride
6. Hardness

220-24.3 SAMPLING

220-24.4

The Oil King should always be concerned about the source of his sample and the manner in which the sample is taken. A sample that represents the larger body of material is necessary. Relatively little difficulty is encountered in sampling feedwater and boiler water because the waters are usually agitated and are well mixed solutions; however, sampling errors do occur.

220-24.5

Sampling errors may be classified as systematic or random. Systematic errors occur if the sample is drawn from one part of a body of liquid when the liquid is not mixed and different levels of concentration exist throughout. The test results tend to be always high or always low. A systematic error can result when sampling an idle boiler. Systematic errors are difficult to avoid in similar sampling situations.

220-24.6

The random error can give either high or low results. An Oil King can usually recognize this error because results are not in conformance with what is expected. The random error is more easily corrected since a new sample can be obtained to check the original result. If boiler water is inadvertently sampled while a chemical addition is in process and high results are obtained, a random error has occurred. When a boiler water sample line is not flushed properly, the analysis could show low pH or phosphate even though the boiler water is properly treated. A random error has occurred. Paragraphs 220-24.77 through 220-24.81 give examples of sampling errors.

220-24.7

Errors in sampling can be alleviated by adherence to the procedures specified in Section 26.

220-24.8 TEMPERATURE

220-24.9

The influences of temperature are varied and significant. Hot water expands, so if the volume of a hot solution is measured and the water cools, less volume is observed. Temperature affects the solubility of all treatment chemicals and contaminants, including dissolved gases, in all water. Temperature affects the reaction rate in all test procedures. The pH changes with changes in temperature. Throughout the sampling procedures of Section 26, temperatures are specified to minimize analytical errors resulting from these considerations.

220-24.10 TIME

220-24.11

In order to promote reproducible results, a specific time lapse is required in certain sampling and test procedures. Sampling procedures are always sensitive to allowing sufficient time for flushing away of stagnant water in the sample line. Dissolved oxygen samples are sensitive to trapped air bubbles in the sample. In most cases, proper flushing will remove all trapped air bubbles. pH and conductivity change with time and air exposure because of absorption of carbon dioxide from the atmosphere. For this reason, feedwater and boiler water samples should always be analyzed immediately after collection. The observance of imposed time restrictions aids in obtaining valid and reproducible results. All tests shall be completed within 30 minutes of sampling.

220-24.12 CLEANING GLASSWARE AND PLASTICWARE

220-24.13

The glassware and plasticware supplied with the test cabinet and kits consists of graduated cylinders, reagent bottles, sample bottles, and so forth. Burets are handled differently from the rest of the glassware and are discussed in paragraph 220-24.26.

220-24.14

When glassware or plasticware is first received, it should be carefully cleaned even though new. Two or three rinsings with tap water, agitation with a mild detergent solution, several rinsings with tap water, and finally, two rinsings with small amounts of distilled water are generally sufficient to clean the equipment. The film of water which adheres to the sides of a glass container after water is discarded should be uniform. Traces of grease or other contaminants cause the liquid to adhere in droplets rather than as a uniform film. If droplets remain on the walls of glassware after cleaning, the glassware is still dirty. Uneven wetting of the surface causes irregularities in volume measurements and in the shape of the meniscus. This will result in measurement errors. Immediately after every use, flush glassware and plasticware with distilled water. Periodically, all glassware and plasticware should be cleaned with detergent and water as previously described.

220-24.15

If a container is not cleaned immediately after use and the liquid is allowed to evaporate to dryness, the residue may be difficult to remove. Concentrated detergent solutions should be avoided. No equipment should be soaked in detergent for longer than 30 minutes. For stubborn deposits, a soft bristle or sponge cleaning should prove successful. Chloride indicator stains the casserole. If the stain persists, it can be removed by applying some of the nitric acid stock solution, followed by distilled water rinsing. (Wear goggles and plastic or rubber gloves when handling nitric acid stock solution.) The reagents used in the hardness test eventually will permanently stain the casserole. This requires casserole replacement.

220-24.16 RINSING OF EQUIPMENT PRIOR TO ANALYSIS

220-24.17

Rinsing of equipment prior to use in an analysis ensures that only the sample of interest is undergoing analysis. In most cases equipment is thoroughly rinsed with distilled water and then with the sample before use. Included in the equipment requiring rinsing with the sample prior to use are pH electrodes, sampling bottles, graduated cylinders, conductivity test bottles, conductivity cells, and thermometers.

220-24.18

Three major exceptions to the general rule of rinse with sample are: the casserole and stirring rod used in chloride, phosphate and hardness analyses, and reagent bottles. In these cases, the casserole, stirring rod, or bottle is rinsed with distilled water only, and then the measured volume of sample is added. We are interested in the analysis of the correct volume of sample, and do not want an unknown additional amount of sample introduced through incorrect rinsing. The minor amount of distilled water left behind from the distilled water rinse has no effect on the test results. Adherence to the procedures specified for each test method or method of preparing reagents will avoid difficulty.

220-24.19 VOLUMETRIC METHODS

220-24.20

Volumetric methods are those which consist of adding a reagent solution (titrant) of known concentration, from a buret, into a sample of known volume to analyze for the concentration of a particular substance. When enough reagent has been added to react with all of the desired substances, the point at which reaction is completed is called the end point. The end point must be recognizable to the person conducting the determination; hence, the use of color indicators. The volume of titrant required is then read from the graduation marks on the buret. Since the concentration and volume of reagent are known, the concentration of the substance can be calculated.

220-24.21 VOLUME MEASUREMENT - READING THE MENISCUS.

The top surface of a column of liquid in any cylinder will have a curvature called a meniscus. Burets, graduated cylinders, and other measuring devices have been calibrated so that the bottom level of the meniscus of the liquid is its volume measuring point. In reading the meniscus, the observer's eye should be horizontal to the meniscus (Figure 220-24-1). If difficulty is experienced in viewing the meniscus, a meniscus reader may prove helpful. This device consists of a white index card with a heavy dark line. Hold the card behind the container with the dark band parallel to and slightly below the meniscus. Light reflected from the surface of the liquid makes the meniscus clearer. Optionally, a plain piece of white paper angled backward behind the meniscus will also serve as a viewing aid as will placing a hand behind the buret at the level of the meniscus.

220-24.22

In reading a buret, if the bottom of the meniscus is exactly on a graduated line, read that value. If the bottom of the meniscus is below a graduated line, read the next value (Figure 220-24-2).

220-24.23

In measuring volumes in graduated cylinders or other calibrated devices, add solution until the bottom of the meniscus is exactly at the graduation line of the desired volume. Figure 220-24-1 shows an example for solution in a graduated cylinder at 50 ml.

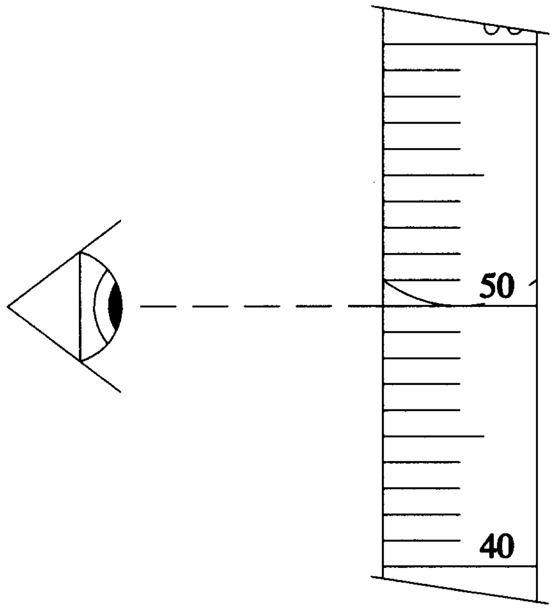


Figure 220-24-1. Viewing the Meniscus (Graduated Cylinder)

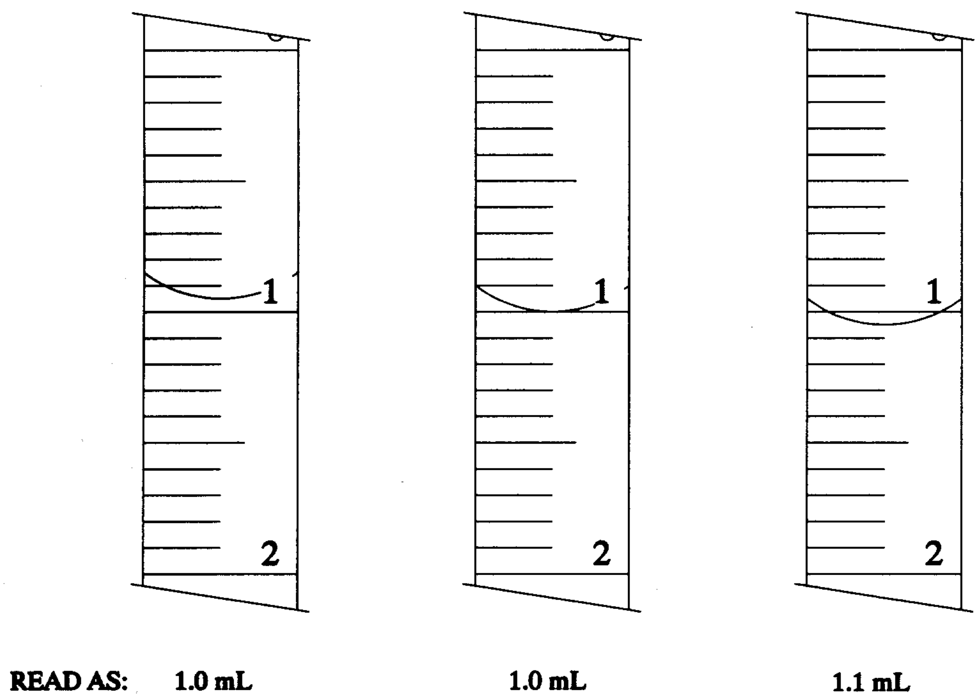


Figure 220-24-2. Reading the Meniscus (Buret)

220-24.24

Graduated cylinders have two designations, TC and TD. A TC cylinder is calibrated **to contain** the measured volume of solution. If this type of cylinder is used in a technique that requires pouring a specified volume of water into another container, the volume transferred will be less than that measured. A TD cylinder is calibrated **to deliver** the desired volume into another container. The TD cylinder shall be used in shipboard tests.

220-24.25

When a reagent bottle is first received, the bottle will contain a 1,000 ml marking. Check the accuracy of this marking by filling a 100-ml TD graduated cylinder successively with 10 increments of 100 ml of distilled water and pouring the water into the reagent bottle. Mark the measured 1,000-ml level with a permanent scribe.

220-24.26 BURETS.

The buret assembly requires preparation for nitric acid and mercuric nitrate reagents. To mount a buret in the two-hole rubber stopper, wet both the barrel of the buret and a hole of the stopper with water. While both are wet, using a twisting motion, gradually insert the barrel through the stopper hole. Similarly insert the glass tubing of the aspirator bulb assembly through the other hole. The bottom of the buret should not touch the bottom of the reagent bottle when the stopper is in place, but should be about 1/2 inch above the bottom of the bottle. Remove the stopcock plug from the buret. Do not misplace the rubber washer. Grease the complete bearing surface of the stopcock plug with bare minimum of the stopcock lubricant from the tube. Apply grease with a fingertip. Insert the plug into the stopcock barrel and rotate it several times. Replace the washer. A properly lubricated stopcock should seat firmly and rotate freely. Over-lubrication allows the stopcock to slide too easily, and grease may plug the bore or tip. Under-lubrication causes the stopcock to leak and to operate stiffly or unevenly. Fine copper wire may be used to remove grease (or deposits) from the bore of the stopcock plug and the delivery tip. Delivery tips clogged by dried chemicals can be cleaned by immersion of the tips in hot water. Maintain each buret full of reagent when on a standby basis. Drain the liquid in a buret and replace it by liquid from the 1,000-ml reagent reservoir bottle on a daily basis. If a buret is not used at least once daily, drain it. In placing the buret back into service, fill the buret with its reagent, then drain it and refill it prior to normal use. Check each buret after filling to make sure it will automatically zero. If a buret automatically fills to the 0.1 ml or other graduation level, mark this fact on the buret and subtract 0.1 ml or the appropriate correction from every titration value obtained. If a buret automatically fills to above the zero reading, replace the buret. If a replacement buret is not available, drain down the buret to the zero level prior to every titration. In replacing a buret, cut the rubber stopper with a sharp knife to remove the glass tubing aspirator bulb assembly. Scrape the glass buret barrel free of any adhering rubber. Use a new rubber stopper to remount the buret assembly. (The rubber stoppers now in the stock system can be used as a solid stopper or as one-, two- or three-hole types because the individual holes are plugged. The user cuts the plugs as needed.)

WARNING

Whenever inserting glass through a rubber stopper, hold the glass with a towel in case of accidental breakage. Do not hold the bottom of the stopper against the palm of the hand during these operations because even though the glass has been fire-polished, it can cut through the palm.

220-24.27 TITRATION.

Every volumetric analysis has a common experimental operation, the titration. Titration is the measured and controlled addition of reagent solution (titrant) to a sample solution with which it reacts. Prior to performing a titration, the analyst must assure that the buret is zeroed and that the delivery tip is full. If an air bubble is trapped anywhere in the delivery tip, remove the stopcock washer, place a waste container under the tip, open the stopcock, and move the stopcock up and down slightly. (Do not pull the stopcock completely out.) This should dislodge the trapped air bubble. Close the stopcock, replace the washer, and refill the buret. If an air bubble is trapped in the column of liquid, gently tap with a pencil or fingernail to dislodge it.

220-24.28

In performing a titration, a right-handed operator should manipulate the stopcock with the left hand while exerting slight downward pressure to avoid pulling the stopcock upward. The right hand is used to continuously stir the sample while the titrant is added.

220-24.29

Most titrations performed aboard ship result in small volume usages of titrant. If the expected titrant usage is less than 2 ml, titration should be performed by adding titrant one drop at a time to the sample. This technique helps to avoid overshooting the end point. Larger volumes of titrant may be added more quickly until the approach of the end point, after which it should be added one drop at a time.

220-24.30 INDICATORS.

In order to determine when a reaction is complete, the end point must be obvious to the analyst. Color indicators are used for this purpose. A titration is complete when the indicator first changes to the correct color. For example, in the final step of the chloride titration, the indicator changes from yellow to light blue-violet. A dark purple color results from over-titration (except in the case of extremely low chloride, where one drop of mercuric nitrate may give a dark purple color). A common analytical technique used in determining end points is: titrate to the anticipated pale color change, read the buret, record the value. Add one more drop of titrant. If the color deepens but does not change further, the end point had been reached at the previously recorded reading. (In the phenolphthalein test the change is from pink to colorless. If the addition of an extra drop shows no further disappearance of color, the end point had been reached.)

220-24.31

Glass indicator dropper bottles have grooves in the ground glass neck and cap to allow a drop-by-drop transfer of indicator. To dispense indicator, align the grooves. When dispensing indicator, hold the cap with the forefinger to prevent spillage of the cap and bottle contents into the receiver. It is preferable to check the flow of the indicator over a waste container before adding indicator to the sample. If indicator flows in a stream instead of falling drop-by-drop, offset the grooves until a drop-by-drop addition can be obtained. As an option, plastic drop-dispensing bottles are available for use instead of the glass dropper bottles. The actual number of drops of indicator added to a large volume of water in volumetric methods is not usually critical. Two to three is routine. Volumetric methods specify a certain number of drops to prevent either very deep coloration or lack of sufficient coloration in the sample, both of which mask the end point. If the analytical technique is maintained reproducible from sample to sample, results will remain reproducible, so the amount of indicator added should not vary from procedural requirements.

220-24.32 OPTICAL METHODS (COLORIMETRY)

220-24.33

Optical methods of analysis (absorption of light) are among the most valuable methods used in quantitative measurements. Colorimetry is one of the most important optical methods. Colorimetry involves comparison of a color developed in a sample with standard colors. The dissolved oxygen and hydrazine tests require visual comparison of the color developed in a sample with standard colors preserved in sealed tubes mounted in a comparator. The silica test uses a colorimeter to make the color determination. In either test, conditions that interfere in the color determination must be avoided (for example, water droplets, water marks or fingerprints on the sample cells, ampoules or comparator).

220-24.34 DISSOLVED OXYGEN AND HYDRAZINE TEST KITS.

These kits require no preparation prior to use. The supplied utility and chain clamps should be permanently installed near the feedwater sample cooler to support the glass sampler. Store the comparators in the plastic case in an area where the temperature is preferably below 27°C (80°F) but not exceeding 38°C (100°F). Clean the top and bottom of the comparator by wiping with a damp, soft cloth. Keep the sampler and the snapper clean. The snapper tool will become scored with use; therefore, new snappers should be ordered as needed. The ampoules in storage should not be exposed to light. Once the dissolved oxygen ampoule tip is broken, the test should be completed as quickly as possible to avoid error from absorption of atmospheric oxygen into the sample. Suspended matter in the sample could lead to erroneous results. If suspended matter is present, discard the sample and obtain a new one.

220-24.35 DR-100 SILICA TEST KIT.

The kit consists of one liquid reagent, two powder reagents (contained in reagent powder pillows), a colorimeter, two 10-ml sample cells with caps, clippers, cell holder and four AA alkaline batteries. Insert the batteries into the colorimeter following the procedure in the kit's instruction manual. The reagents require no preparation but must be stored in a cool, dark place. Store the colorimeter and other apparatus in the plastic case. It is important to observe the time intervals between steps specified in the test procedure, as these are necessary to allow the chemical reactions to take place at each step. The sample cells must be kept clean.

220-24.36 COLOR CHANGES

220-24.37

Color changes observed during various volumetric tests and the range of the comparator used in the dissolved oxygen and hydrazine test are listed in Table 220-24-1.

Table 220-24-1. Color Changes in Boiler Water and Feedwater Tests

<table>
<tr><th>Indicator</th><th colspan="2">Color Changes in Titration</th></tr>
<tr><td>Phenolphthalein
Methyl purple
Chloride (feedwater)
Chloride (boiler water)
Hardness</td><td colspan="2">Pink or red → colorless[*]
Green → gray → purple[*]
Red or pale violet → yellow → pale violet[*]
Red or pale violet → yellow → pale violet[*]
Red or purple → blue[*]</td></tr>
<tr><th>Test</th><th>Range of Comparator</th><th>Color Gradation of Comparator</th></tr>
<tr><td>Dissolved Oxygen</td><td>0-40 ppb</td><td>Shades of pink</td></tr>
</table>

Table 220-24-1. Color Changes in Boiler Water and Feedwater Tests - Continued

Indicator	Color Changes in Titration	
Hydrazine	0-500 ppb 0-100 ppm	Shades of yellow

*Last color is the end point of the titration.

220-24.38 ELECTROMETRIC METHODS

220-24.39

Electrical conductivity meters and salinity indicators both measure conductivity though the readout for salinity indicators is calibrated in epm chloride (refer to paragraph 220-24.70). These equipments are installed in all naval ships. Their operation is based upon the fact that the electrical resistance of a water solution varies with the amount of ionized salts dissolved in it. This resistance and the corresponding meter indication vary with the temperature, as well as with the ionized salt concentration of the water. Temperature compensation (automatic or manual) is provided to eliminate the temperature effects of the solution. The compensator setting must correspond to the temperature of the solution being measured.

220-24.40

All ships with propulsion boilers that use coordinated phosphate/pH boiler water treatment have pH measuring equipment. Refer to Section 31 for information on pH equipment.

220-24.41 BOILER WATER CONDUCTIVITY TEST EQUIPMENT.

The conductivity test equipment, required for the boiler water conductivity test of propulsion boilers, consists of a Beckman meter (a Wheatstone bridge with null balance lights) plus a dip cell, thermometer, and two square bottles (one for dip cell storage, the other as a test sample container). The meter should be mounted on a bulkhead and its power source shall be 110-115 volts. The dip cell has a cell constant of 2.0. Use of a dip cell with a constant other than 2.0 will result in erroneous boiler water conductivity readings. The dip cell, in between tests, shall be stored in distilled water. The distilled water used for storage shall be replaced daily. If the cell is not to be used for a week or more, rinse the cell electrodes thoroughly with distilled water, shake off the excess water and store the cell in the dry state. The electrodes should not be touched by any object in an attempt to clean them. The null balance eye, after some use of the probe, may lose its sharpness. This is due to insoluble salts forming on the surface of the electrodes. Sharpness can frequently be restored by dipping the cell for 2 minutes in 10 percent (by weight) hydrochloric acid and rinsing the cell with distilled water. The cell should be replaced if no improvement is noted after this treatment. The hydrochloric acid treatment is to be performed only in a shipyard chemical laboratory.

220-24.42 SALINITY INDICATORS AND FEEDWATER CONDUCTIVITY CELLS.

The salinity indicators and feedwater conductivity cells should be operated and checked as recommended in the manufacturer's instruction book supplied with the equipment. To further ensure that the equipment is operating properly, the maintenance schedule set forth in the Maintenance Requirements Cards (MRC's) must be followed. The results obtained with the salinity indicator must be compared with the corresponding chloride titrations on a daily basis. Normally, the salinity indicator reads out in μhmo/cm. Read the meter to the nearest 0.1

µhmo/cm. Although all salinity indicators measure conductivity, some are labeled to read equivalents per million (epm) chloride. Others indicate parts per million of chloride or grains per gallon (gpg) sea salt. To convert these readings to epm, divide ppm by 35.5 or multiply gpg by 0.261. To convert conductivity readings in µmho/cm to epm chloride, divide the conductivity reading by 145.

220-24.43 CALIBRATION.

Conductivity meters and pH meters are calibrated aboard ship by use of standards. The terms standardization and calibration are used interchangeably in the Navy Metrology and Calibration Programs (METCAL). Neither pH nor conductivity meters, as applied to boiler water and feedwater testing, are routinely referred to a calibration facility for calibration. The **User Calibration** label is affixed the first time the standardization is performed by the user, and this label is not replaced at each standardization. When the label is first affixed to the instrument, it is annotated as to the appropriate calibration interval. The record of calibration (standardization) performed is maintained on the boiler water log. **User Calibration** labels (NAVSEA 4734/19) are available under NSN 1I 0116-LF-009-5800.

220-24.44

When a bimetallic thermometer is first received, or if operation is suspect, its function should be checked by immersion of the stem in an ice water bath. If the dial indicator is not 0°C (32°F), replace the thermometer.

220-24.45 PREPARATION OF REAGENTS AND INDICATORS

220-24.46

The testing of feedwater and boiler water samples requires reagents of certain concentrations. Most of these reagents are prepared by diluting a measured volume of stock solution to a definite final volume. Some of the reagents are supplied ready for use and need little or no preparation. All of the stock reagents are listed in Section 28. For accurate test results, it is necessary that the reagent be prepared according to the following directions.

220-24.47 NITRIC ACID REAGENT.

Nitric acid reagent is used in the phosphate, chloride, and emergency pH tests. Nitric acid reagent has a strength of 0.05 N and is prepared from a 1.0 N nitric acid stock solution as follows:

WARNING

Wear goggles and plastic or rubber gloves when handling the 1.0 N nitric acid stock solution. It contains about 6 percent nitric acid by weight.

1. Rinse the 1,000 ml nitric acid reagent bottle with distilled water.
2. Rinse a 100 ml graduated cylinder with distilled water and then with a small portion of the 1.0 N nitric acid solution.
3. Measure 50 ml of the stock solution with the graduated cylinder and pour the 50 ml of stock solution into the 1,000 ml reagent bottle.

4. Fill the reagent bottle to the 1,000 ml mark with distilled water.
5. Stopper the bottle and shake well to mix.
6. Label the bottle with the preparation date and the appropriate expiration date from the stock chemical.

220-24.48 MERCURIC NITRATE REAGENT.

The mercuric nitrate reagent is used in the chloride test. The mercuric nitrate reagent has a strength of 0.01 N and is prepared from a 0.5 N mercuric nitrate stock solution as follows:

WARNING

Wear goggles and plastic or rubber gloves when handling the 0.5 N mercuric nitrate stock solution. It contains nitric acid needed to dissolve mercuric nitrate. If the 0.5 N mercuric nitrate stock solution is spilled, absorb the spill with rags. Transfer the rags to a sealable plastic bag. Mark the bag contains mercury waste, and hold for shore disposal.

1. Rinse the 1,000 ml mercuric nitrate reagent bottle with distilled water.
2. Rinse a 100 ml graduated cylinder with distilled water and then with a small portion of the 0.5 N mercuric nitrate stock solution. Pour the mercuric waste into a plastic 5-gallon bottle identified as containing mercury waste.
3. Measure 20 ml of the stock solution with the graduated cylinder and pour the 20 ml of stock solution into the 1,000 ml reagent bottle.
4. Fill the reagent bottle to the 1,000 ml mark with distilled water.
5. Stopper the bottle and shake well to mix.
6. Label the bottle with the preparation date and the appropriate expiration date from the stock chemical.
7. Rinse the graduated cylinder with distilled water and pour the rinsings into the plastic 5-gallon bottle.

WARNING

Bottles or plastic bags containing mercury wastes should be turned in to the Public Works Officer or Public Works Center at any shipyard or other Navy industrial facility.

NOTE

When the 4-ounce bottle of mercuric nitrate stock solution is empty, rinse the bottle with distilled water and pour the rinsings into the plastic 5-gallon bottle identified as containing mercury waste.

220-24.49 PHENOLPHTHALEIN INDICATOR.

Phenolphthalein indicator is used in the phosphate, feedwater pH, and alkalinity tests. The indicator solution is 1 percent phenolphthalein in isopropyl alcohol and distilled water. It is prepared from phenolphthalein dry powder, as follows:

1. Rinse the phenolphthalein indicator dropper bottle (either glass or plastic) and its stopper with a small portion of isopropyl alcohol.
2. Using a brass dipper, measure 2 level dippers of the phenolphthalein into the dropper bottle. **Be careful to thoroughly clean the dipper before and after measuring phenolphthalein** .
3. Rinse a 100 ml graduated cylinder with distilled water and then with a small portion of isopropyl alcohol.
4. Measure 25 ml of isopropyl alcohol with the graduated cylinder and pour it into the dropper bottle, washing down any of the phenolphthalein powder clinging to the inside walls.
5. Stopper the bottle in closed position and shake until all of the phenolphthalein is dissolved.
6. Measure 25 ml of distilled water with the graduated cylinder and pour it into the dropper bottle.
7. Stopper the bottle in the closed position and shake to mix.

220-24.50 METHYL PURPLE INDICATOR.

Methyl purple indicator is used in the phosphate test and shore feedwater/steam condensate pH test. The indicator is supplied in powder form contained in capsules. The solution is prepared as follows:

1. Rinse the methyl purple indicator bottle and stopper with distilled water.
2. Tap the contents of one methyl purple indicator capsule into the dropper bottle.
3. Rinse a 100 ml graduated cylinder with distilled water.
4. Measure 50 ml of distilled water with the graduated cylinder and pour into the dropper bottle.
5. Stopper the bottle in the closed position and shake until all of the powder has dissolved.
6. Measure 10 ml of isopropyl alcohol with the graduated cylinder and pour it into the dropper bottle.
7. Stopper the bottle in the closed position and shake to mix.
8. Mark the date of preparation and the expiration date of 6 months from date of preparation on the bottle.

220-24.51 CHLORIDE INDICATOR.

Chloride indicator is used in the chloride test. The indicator is supplied in powder form contained in capsules. The indicator solution is prepared as follows:

1. Rinse the chloride indicator bottle and stopper (either glass or plastic) with distilled water and then with a small portion of isopropyl alcohol.
2. Empty the indicator powder from one capsule into the dropper bottle.
3. Rinse a 100 ml graduated cylinder with distilled water and then with a small portion of the isopropyl alcohol.
4. Measure 50 ml of isopropyl alcohol and pour into the dropper bottle.
5. Stopper the bottle in the closed position and shake until all of the powder has dissolved.

6. Mark the date of preparation and the expiration date on the bottle. Expiration date is the same as the expiration date of the capsule, or 9 months after preparation, whichever comes first.

220-24.52 DISSOLVED OXYGEN AMPOULES.

A sealed glass ampoule for the dissolved oxygen test contains sufficient reagent for one test. No preparation is required prior to use. The ampoules must be stored so that they are not exposed to light, as light causes degradation of the reagent.

220-24.53 DISSOLVED OXYGEN COMPARATOR.

If comparator is not labeled with expiration date, mark the expiration date two years from the date of receipt.

220-24.54 HYDRAZINE AMPOULES.

A sealed glass ampoule for both low range and high range hydrazine tests contains sufficient reagent for one test. No preparation is required prior to use. The ampoules must be stored where they are not exposed to light, since light causes degradation of the reagent.

220-24.55 HYDRAZINE COMPARATORS.

Mark the expiration date 2 years from the date of receipt. When not in use, store in the dark at temperature above freezing and below 100°F (38°C). The comparators are cleaned by wiping with a clean, damp cloth. Keep the sample cup clean.

220-24.56 DILUTED CAUSTIC SODA SOLUTION.

Diluted caustic soda is used in the phosphate test when boiler water alkalinity is zero.

WARNING

Wear goggles, plastic or rubber gloves and apron when handling solid caustic soda. Caustic soda is lye.

1. Rinse a plastic drop-dispenser bottle (60 ml capacity) and its cap with distilled water.
2. Use a spatula to transfer about three flakes of caustic soda into the plastic bottle. If caustic soda is in bead form, use a clean hardness dipper to transfer two full dippers of caustic soda into the plastic bottle.
3. Add distilled water to the shoulder of the bottle.
4. Cap the bottle and shake to dissolve the caustic soda. Hold the flip-cap secure while shaking the bottle.
5. Label the bottle **Diluted Caustic Soda** .
6. Rinse spatula/dipper with distilled water after use.

NOTE

Caustic soda reacts with carbon dioxide from the atmosphere to form sodium carbonate. Sodium carbonate interferes in the phosphate test. The dull, dry, caked material in a caustic soda can is sodium carbonate. The shiny flakes are caustic soda. Use the shiny material when preparing caustic soda solution. Keep the flip-cap on the plastic bottle closed when not in use.

Check the diluted caustic soda solution as follows:

1. Analyze distillate for **phosphate** following the procedure for the boiler water phosphate test (paragraph 220-26.28).
2. If a **phosphate** result greater than 2.5 ppm is obtained then the caustic soda used to prepare the dilute caustic soda solution was contaminated with sodium carbonate. Prepare new dilute caustic soda using fresh material and retest.

220-24.57 HARDNESS TEST MATERIALS.

The ethylenediaminetetraacetate (EDTA) hardness test rapidly and accurately measures feedwater hardness. At a pH of about 10 the organic dye used as the hardness indicator is red with hardness present and blue with hardness absent. At this pH, the EDTA titrant reacts with the calcium and magnesium that are causing hardness and prevents them from generating a red color with the indicator. Therefore, as the titration end point is approached, the indicator changes color from red to blue. A special buffer is added to maintain the proper pH. In addition, dimethylglyoxime (DMG) is provided to prevent interference by nickel, should it occur. Because the alkaline titrating solution may attack glass, a buret with a teflon stopcock and a plastic reagent squeeze bottle are required. Prior to initial use, prepare the titration assembly as follows:

WARNING

Wear goggles and plastic or rubber gloves when pouring the hardness titrating solution.

1. Rinse the plastic bottle with two small portions of hardness titrating solution.
2. Fill the plastic bottle with titrating solution as supplied. No dilution is necessary.
3. Slide the rubber insert over the barrel of the buret.
4. Screw the buret assembly onto the plastic bottle.
5. Fill the buret by squeezing the bottle. Allow to drain for flushing.
6. Refill the buret and ensure that air bubbles are absent in the buret tip.
7. Label the 1-pint plastic bottle **Hardness Titrating Solution** .
8. Label the 1-pint plastic bottle with the expiration date from the 1-gallon bottle of hardness titrating solution.

220-24.58

All of the reagents are supplied ready for use. Further preparation is unnecessary.

220-24.59 STANDARDS

220-24.60

The systematic and random errors mentioned under sampling (paragraph 220-24.5) apply as well to errors caused by test techniques, deteriorated chemicals, and faulty equipment. If a reagent solution is prepared incorrectly from a stock solution every test result thereafter will contain a systematic error. If chloride from an extraneous source (for example, perspiration) contaminates a boiler water sample, the chloride result will be in error. The best method of ensuring that analyses are satisfactory is the self-check method. Standards are available for ascertaining the reliability of technique and equipment. Whenever a result is in doubt, test accuracy should be validated by resampling and by analysis of the standard. A quarterly validation of reagents and equipment using the standards is required. The results of standard testing and the date are to be entered on the monthly boiler data log of the number 1 machinery plant. Whenever a new batch of nitric acid or mercuric nitrate reagent is prepared a standard check is required. Standards are supplied ready for use. Follow the applicable procedure of Section 26 when testing standards. If an incorrect result is obtained for any of the validation tests using the standards, this means that either the test reagents, test equipment or standards are not correct. When this occurs, proceed as follows:

1. Restandardize using new reagents and newly prepared standard as appropriate.
2. If the incorrect result is still obtained, advise NAVSEA, NSWCCD-SSES and the Type Commander and send samples of the standard to NSWCCD-SSES, Code 622, for analysis.

220-24.61 FEEDWATER HARDNESS TEST STANDARD.

The standard for the feedwater hardness test chemical with its acceptable limit of results is as follows:

FEEDWATER HARDNESS TEST STANDARD

Standard	Limit
Hardness, 0.2 epm	0.16 to 0.24 epm

220-24.62

Test the hardness standard as a feedwater sample in accordance with the test method in paragraph 220-26.18. If the result obtained does not fall in the range of the established limits, test a second standard. If an incorrect result is still obtained, submit a defective material report and advise NAVSEA, NSWCCD-SSES and the Type Commander.

220-24.63 BOILER WATER TEST STANDARDS.

The standards for the boiler water test chemicals and conductivity equipment with their acceptable limit of results are as follows:

BOILER WATER TEST STANDARDS

Standard	Limit
Alkalinity, 6.0 epm	5.4 to 6.6 epm
Chloride, 2.0 epm	1.92 to 2.08 epm
Conductivity, 1,400 µmho/cm	1,300 to 1,500 µmho/cm

220-24.64

Test the chloride and conductivity standards as boiler water samples in accordance with the test methods, Section 26. Test alkalinity standard using paragraph 220-26.34 to verify nitric acid reagent and methyl purple indicator. If the results obtained do not fall in the range of the prescribed limits, the test chemicals including indicators of the particular test are to be discarded and new test chemicals are to be prepared from fresh stock chemicals. Test a second standard using the new test chemicals.

220-24.65 DETERIORATION OF TEST CHEMICALS AND EQUIPMENT

220-24.66

Test chemicals are subject to deterioration resulting from storage at high temperatures and old age. Deteriorated chemicals are not to be used as they lead to incorrect test results. All test chemicals shall be stored in areas where the temperatures are preferably below 27°C (80°F) but do not exceed 38°C (100°F).

220-24.67 LABORATORY CONDITION

220-24.68

The oil shack is essentially a shipboard laboratory used for testing water and fuel. Since space is usually limited, it is important that the laboratory be maintained in a clean and neat condition. All test equipment shall be maintained as delineated in the foregoing paragraphs and stored in the proper place. Avoid cluttering the laboratory with extraneous material. The material condition of the laboratory and the equipment used therein shall conform to the following specified conditions:

1. Laboratory environment. Clean, orderly, well lighted, and ventilated. Heated or cooled as appropriate. No material other than support material should be located in the laboratory.
2. Cabinet and electrical service equipment. Equipped with operable lights, approved wiring, three prong plugs, and electrical safety tags.
3. Cabinet interiors and exteriors. Clean and well-preserved.
4. Cabinet door and latch. Functional.
5. Cabinet contents. Neatly stowed.
6. Cabinet base. Lined with clean paper towels or rubber sheet.
7. Glassware and plasticware. Clean and free of chips and cracks.
8. Chemical residues. None inside cabinet.
9. Buret stopcocks. Properly lubricated and held in place by rubber washers.
10. Stock solution, reagent, and indicator bottle caps. Easily operable and wiped clean of deposits.

11. Outdated chemical stocks and prepared solutions. Removed from the laboratory and disposed of properly.

12. Chemical disposal procedures. Readily available.

13. Chemical disposal containers. Properly labeled.

14. Chemical test procedures. Available for ready reference. A workbook containing a copy of each test procedure, protected in plastic, and maintained current, is recommended for ease in use.

15. Boiler water treatment volume. Posted on exterior of cabinet door with appropriate reference table from this manual cited.

16. NSTM Chapter 220 Volume 1, Boiler Water/Feedwater - Water Chemistry; NSTM Chapter 220 Volume 2, Boiler Water/Feedwater - Test and Treatment; NSTM Chapter 221, Boilers; NSTM Chapter 255 (9562), Feedwater Systems and Apparatus; NSTM Chapter 505 (9480), Piping Systems; and NSTM Chapter 541 (9550), Petroleum Fuel Stowage, Use, and Testing; NSTM 670, Stowage, Handling, and Disposal of Hazardous General Use Consumables; NSTM 262, Lubricating Oils, Greases, and Lubricating Systems; NSTM 593, Pollution Control; OPNAV INST 4731.1A, Joint Oil Analysis Program; NAVAIR 17-15-50.1 Volume 1, Joint Oil Analysis Program; Oil Lab EOSS/EOP. Maintained current with a copy of each located in the laboratory.

220-24.69 TROUBLESHOOTING

220-24.70 SALINITY AND CONDUCTIVITY INDICATING EQUIPMENT MALFUNCTION.

Salinity and conductivity indicating systems installed on board ship to monitor distillate and condensate system water are manufactured by several different manufacturers. Equipment consists of temperature compensated probes installed in shipboard piping and readout panels with alarms. Components are not interchangeable between manufacturers. The principle of operation is based on the fact that water conducts electricity proportional to the amount of dissolved ionic solids present. In the case of salinity indicators, the readout is calibrated in epm chloride. The epm chloride readout assumes the only contamination present is that which originated from dissolved sea salts. Therefore, the salinity indicator readout in epm chloride is only accurate for chloride when no other contaminant (such as hardness) is present. Both salinity and conductivity indicators actually measure the total conductivity of the water resulting from all dissolved ionic contaminants, not just seawater and not just chloride. Malfunction of the indicator system can be detected by comparison of indicator reading with chemical test results for chloride and hardness. The purpose of the daily comparison tests is to ensure that salinity and conductivity indicators are operating satisfactorily and the feedwater entering the boiler does not contain contamination from seawater or shore water. Salinity and conductivity indicators tend to read slightly lower than chemical test because they are less prone to contamination by absorption of gases from air. For a proper comparison between chemical test and salinity, and conductivity indicators, the sample should be collected as close as possible to the indicator probe location while simultaneously reading the indicator.

220-24.71 DISSOLVED GASES (I.E. AMMONIA AND CARBON DIOXIDE) PRESENT IN COASTAL, RIVER AND PORT WATERS MAY CAUSE HIGH SALINITY/CONDUCTIVITY INDICATOR READINGS.

The presence of dissolved gases, such as ammonia and carbon dioxide, will increase the conductivity of water and thus cause high salinity or conductivity indicator readings. For this reason, the distiller air ejector drain salinity/conductivity indicator often reads higher than the other condensate indicators. High levels of dissolved gases may be encountered when distilling in coastal, river or port waters which could result in salinity/conductivity readings exceeding upper limits for distiller air ejector drains and distillate. If distillate containing high levels of gases is sent to the feedwater tanks, then high readings may be experienced throughout feedwater system. This problem can be avoided by filling feedwater tanks prior to entering coastal areas. When the distillate or distiller air ejector drain salinity/conductivity indicators are reading high due to dissolved gases, use of the water shall be based on the chemical chloride test. Continue to monitor the salinity/conductivity indicators as further increases may indicate contamination. Conduct additional chloride tests as required. Enter a comment in the remarks section of the feedwater log indicating suspected dissolved gas contamination.

220-24.72

Excess morpholine will cause the salinity/conductivity indicators to read out of limits high. This can occur following light-off of a boiler under hydrazine/morpholine layup. Increased salinity or conductivity indicator readings may also result from use of shore steam treated with morpholine or similar chemicals following steam blanket layup or warm-up of DFT. Ensure seawater or shore water contamination is not occurring by testing feedwater for chloride and hardness.

220-24.73

Once it has been ascertained that a salinity or conductivity indicator may be malfunctioning, the cause must be located and corrected, be it the power transformer, indicator panel, external wiring, temperature compensator, or cell. The system should be checked out as follows:

a. Verify proper meter function by using meter check feature.

b. Verify integrity of cell wiring by replacing the cell with test resistor which should cause a 0.261 epm reading at the meter.

c. Clean and test the cell in accordance with paragraph 220-24.74.

WARNING

Never touch cell electrodes with power on. Never open panel with power on. A SHOCK HAZARD EXISTS.

An IC man should perform all additional work necessary. A test resistor is provided with the salinity indicating system which will read about 0.261 epm on the indicator when installed on the cell. Continuity checks should be conducted on conductivity indicating systems in accordance with the system technical manual. This checks wiring from the meter to the cell. The indicator should read zero when the cell is out of water. Consult the particular system's NAVSEA technical manual for more specific details.

220-24.74

To check salinity system or conductivity cells, a test solution can be prepared which will provide an on-scale reading so that the salinity or conductivity cells can be compared with one another as follows:

1. Rinse a clean, spare 1,000 ml reagent bottle and half fill with pure, fresh condensate or feedwater (maximum 0.02 epm chloride by chemical test).

2. Rinse a 100 ml graduated cylinder with 2 epm chloride standard. Measure 50 ml of the standard into the cylinder (two bottles of standard will be needed for rinsing and testing). Pour the 50 ml of 2 epm chloride standard into the reagent bottle.

3. Dilute with condensate or feed to the 1,000 ml mark.

4. Stopper and mix well.

5. The chloride by the feedwater chemical test and by salinity indicator should be between 0.09 and 0.11 epm. Conductivity indicators should read between 13.5 and 16.5 µmho/cm.

NOTE

In order to avoid gas absorption, do not allow the test solution to be exposed to the air. The test solution should not be stored. Use at once.

6. Turn off power to salinity/conductivity indicator.

7. Remove suspect cell from piping in accordance with the manufacturer's instruction manual.

8. Shake cell to remove water and rinse well with distilled water and then test solution in a beaker.

9. Immerse probe in fresh test solution and turn on salinity indicator.

10. Permit cell to reach sample temperature.

11. Record salinity reading; turn off power.

12. Rinse cell with distillate.

13. Repeat steps 1 through 12 for a new cell as quickly as possible. It may be advisable to connect both cells to a multichannel panel following the instructions in the indicator system's NAVSEA technical manual. This will minimize test solution exposure to air since the two readings can now be obtained almost simultaneously simply by turning the terminal selector switch dial.

14. Results should agree within 3 percent if the cells are functioning. If they do not agree, replace the old cell with the new one.

220-24.75

Cell electrodes are easily contaminated with suspended solids and oil, particularly gland exhaust condensate, which will lead to inaccurate readings. Therefore, salinity indicator systems must be maintained properly by cleaning and inspecting panels and cells monthly is accordance with PMS. The outer electrode of some salinity cells is removable. Though mechanically interchangeable, these electrodes should not be affixed to another cell because the inner and outer electrodes are matched in each cell. If either electrode is dented or otherwise damaged, the cell should be replaced.

220-24.76 DEFECTIVE TEST CHEMICALS AND EQUIPMENT.

Equipment and chemicals can be used without difficulty if sufficient supplies of chemicals are maintained, chemicals are properly identified on receipt and stored properly, and equipment operating details outlined in this volume are closely observed. The following list of possible equipment problems will assist in troubleshooting.

1. Clogged buret tips are caused by excessive stopcock lubricant or infrequent testing. Clean with hot water or cold alcohol, by immersing the tip. A thin wire may be carefully inserted in the tip to loosen the clogging material.

2. Leaking stopcocks are caused by interchanging stopcocks between burets. If a proper buret cannot be found, use slightly more lubricant as a temporary repair until a properly matched buret and stopcock are obtained.

3. Standard test solutions are provided to check test procedures and reagents. Chemicals and equipment shall be

tested at least quarterly, whenever new reagents are prepared, and whenever a suspicious result is obtained. Should unacceptable standard test results be encountered, then one of the following is the cause:

a. Deteriorated test chemicals, or indicators.

b. Test chemicals improperly diluted or mixed.

c. Contaminated test chemicals.

d. Use of isopropyl alcohol other than that specified in paragraph 220-28.5 may result in test difficulties.

e. Distilled water should be obtained from ships distilling units, provided the chloride is within limits. Battery water is not an acceptable substitute for distillate.

f. Stock chemicals have improper concentration (normality).

g. Improper reagent bottle volume. One thousand ml is specified. It is a good practice to verify the volume upon receipt using the 100 ml graduated cylinder from the boiler water test kit to determine the exact 1,000 ml liquid level. This level should be marked with a permanent scribe.

h. Dirty equipment.

i. Malfunctioning conductivity cell or meter. To isolate the cause, replace the old cell with a new cell and retest. If a satisfactory result is obtained, replace the first cell. If the result is unsatisfactory, replace the meter and confirm the malfunction by retest. It should be noted that the cell must have a cell constant of 2.0 for correct results. Use of a cell with a constant of 0.1 will give high readings 20 times the actual value. The meter must have a stated reference temperature of 25°C (77°F). Use of a meter with reference temperature of 18°C (64°F) will result in low readings (approximately 15 percent). Null balance eye sharpness, if lost, can be restored by dipping the cell for 2 minutes in 10 percent hydrochloric acid and rinsing thoroughly with distilled water (to be accomplished by shipyard personnel only).

4. Other problems with stock chemicals and standard solutions have arisen such as:

a. Methyl purple indicator turning blue instead of the desired green when dissolved.

b. Indicator capsules not containing the correct amount of the indicating chemical.

c. Standard solutions not containing the correct volumes of solution.

NOTE

When a problem with boiler water/feedwater test and treatment chemicals or equipment is identified, a defective material report shall be submitted in accordance with NAVSUPINST 4440.120.

220-24.77 PROBLEMS IN SAMPLING.

Several sampling problems can cause false test results. These are described in the following paragraphs.

220-24.78 RESERVE FEEDWATER.

Reserve feedwater is normally sampled through the tank sounding tube using a thief sampler. Sounding tubes are to be capped when not in use. Holes have been drilled in sounding tubes from the tank top to the bottom of the tube to permit representative sampling. On some ships, sounding tube holes have not been drilled and in this case, the sample obtained may not be representative of the tank's water. This can result in samples containing higher hardness than actually present throughout the tank due to normal slight corrosion of the sounding tube and buildup of dissolved and suspended solids in the water within the tube. If sounding tube holes are absent, a representative sample can be obtained via the reserve feed transfer pump.

220-24.79 DEAERATED FEEDWATER.

Investigation of high dissolved oxygen problems in boiler feedwater indicates that in many cases erroneously high test results are obtained due to sampling system deficiencies and improper test procedures. Attention to detail and strict adherence to established procedures are mandatory in order to obtain representative dissolved oxygen samples and valid results. However, a high oxygen result should not be neglected by attributing it to improper analysis. The starting point in identifying the problem should be the test method and setup utilized for collecting and analyzing the dissolved oxygen sample. Several conditions which can cause false high results are as follows:

1. The sampling line leading from either the DFT or feed booster pump suction line is leaking or restricted.
2. Improper temperature of the sample. A sufficient supply of chilled water must be provided to cool the sample below 100°F (38°C). Prior to collecting the sample, temperature must be between 70°F to 100°F (21°C to 38°C). The sample line must be hot flushed (with coolant pressure relieved), and proper flush periods must be observed to ensure representative sampling.
3. The sample coolers employed are manufactured in accordance with MIL-C-17557. It is possible for cooling water to leak into the sample if the coil has deteriorated. The method of detection is the comparison between the chemical chloride test and the DFT salinity indicator. The cooler is suspect if chloride and hardness occur at the DFT by chemical test without a DFT salinity indicator rise. To confirm a leak, samples can be obtained simultaneously from both the cooler and the DFT gauge glass using ice and coiled copper tubing to cool the gauge glass sample taking care not to contaminate the sample. If the chloride content is higher on a sample from the cooler, the cooler must be hydrostatically tested on the coolant side. Obviously, this depends to a great extent on the quality of the cooling medium. Coolers using saltwater as coolant will give a higher chloride result during leakage than coolers using chilled freshwater. A simple routine test for gross leakage consists of subjecting the cooler to full system coolant pressure (sample inlet valve secured), and collecting drippings from the sample cooler effluent. If substantial liquid is collected, either the sample line root valve is partially open or the cooler is leaking coolant into the sample. If the chloride level on this sample approximates the chloride in the cooling medium rather than the DFT, then the cooler should be hydrostatically tested. Bulged coolers indicate coolant shell pressure has not been relieved during hot flushing for dissolved oxygen (safety hazard). Sample coolers using chilled water from the air conditioning main shall have coolant inlet valves locked open to preclude the possibility of cooler damage due to heating of trapped water. Replace bulged coolers.
4. The sample discharge from the coolers to the collection bottle should be as direct as possible. The rubber tubing should fit tightly over the sample outlet, not inside it. Any leakage at this junction is unacceptable. No threaded fittings are permitted. It should not be presumed that because sampling lines are under positive pressure water can leak out but air cannot leak in. In the configuration of fittings sometimes utilized, venturi effects may exist which will create an inflow of air rather than a leakage of water. If any leakage into the sampling line is suspected, the piping should be hydrostatically tested. If a flow of air bubbles is noticed in the glass sampler during sampling, then the piping system is defective. To preclude the foregoing, DFT sampling systems shall be installed in accordance with NAVSEA dwg 803-1385735.

220-24.80 BOILER WATER.

Boiler water samples can yield faulty results for any of several reasons. These are:

1. Failure to obtain a representative sample because the sample line was not properly flushed.
2. Failure to cool the sample below 38°C (100°F).
3. Failure to use a clean sample bottle.

4. Failure to thoroughly rinse the sample bottle and cap with sample before filling.
5. Failure to completely fill and cap the sample bottle.
6. Drawing a sample from the wrong boiler.
7. Leakage of water from the other boiler into the sample cooler in ships where two boilers are served by the same cooler.
8. Leakage of cooling water into the sample side of the sample cooler.

220-24.81 SAMPLE COOLER LEAKAGE.

Cooler leakage wherein cooling water contaminates the sample is often indicated by the inability to effect changes in boiler water test results by blowdown, chemical treatment, or dumping the boiler. Since many boiler water coolers (MIL-C-17557 Type 1) are cooled by saltwater, the chloride test result may be high, which would normally indicate sea salt contamination of the boiler. Gross coolant leakage can be detected by applying full coolant pressure to the cooler (coolant outlet valve secured) with the sample inlet valves secured. Drippings, if any, are collected from the sample discharge line and the chloride content determined. If the chloride content is higher than the last boiler water test results, leakage is occurring and the cooler must be subjected to hydrostatic test. Do not attempt sampling from the gauge glass of a steaming boiler. During any boiler water sampling, it is important to initiate full coolant flow before sample flow or the cooler may become scaled causing loss of efficiency and possible rupture. If one cooler serves two boilers, extreme care must be used to ensure that the sample is collected from the correct boiler. All sampling valves in these systems must be maintained in good condition. If a sample cooler is leaking or becomes clogged, secure the boiler until the problem is corrected. The Commanding Officer should be notified that the boiler should be secured. If the Commanding Officer directs continued steaming with a leaking or clogged sample cooler, note this in the boiler water log and continuously monitor salinity/conductivity indicators for possible contamination.

NOTE

Additional coolers are being added by an approved SHIPALT to ships with only one cooler for more than one boiler.

220-24.82 TROUBLES WITH BATCH CHEMICAL INJECTION.

Failure of boiler water alkalinity or phosphate to rise after chemical injection indicates a problem. Either the treatment chemicals did not get into the boiler, or the treatment chemicals injected were not the right material. Improper chemical injection procedure, improper valve lineup, plugged treatment lines or leaking valves could cause chemicals to be injected to the bilge or to another boiler in the space, or not at all. This can be checked by visual inspection of the tank drain during injection, by double checking the valve lineup, and by sampling the other boiler for unexpected rise in alkalinity or phosphate.

SECTION 25.

CHEMICAL SAFETY PRECAUTIONS, HANDLING, AND STORAGE PROCEDURES

220-25.1 CLASSIFICATION OF HAZARDS

220-25.2

There are a number of safety precautions to be observed when testing or treating boiler water and feedwater. Many of the chemicals employed are either acids or alkalies. All are poisons when ingested. Sampling can be dangerous if procedures are not followed exactly or if equipment is faulty because live steam can discharge. Coolers can rupture because of the pressures involved. For boiler water sampling, the cooling water flow must be established prior to opening any valve in the sample line. For dissolved oxygen sampling, pressure in the secured cooling water line must be relieved. Table 220-25-1 lists precautions to be employed when using test or treatment chemicals. Immediate medical attention shall be obtained if any chemical is swallowed. Contaminated clothing shall be laundered prior to reuse.

220-25.3 ACIDS.

Nitric acid is used in the phosphate test and mercuric nitrate stock solution contains nitric acid. The ammonium molybdate reagent used in the silica test contains sulfuric acid. The hydrazine ampoule contains hydrochloric acid. The amino acid reagent contains 1-amino-2-naphthol-4-sulfonic acid. Also, citric acid is used in the silica test. Do not mix acids directly with alkalies because the heat generated may cause the solution to spatter. If acids contact the skin, flush affected skin with cold water. If a burning or itching sensation persists, or if a rash develops, seek medical attention. If acids come in contact with the eyes, flush with large amounts of potable water and obtain immediate medical attention.

220-25.4 ALKALIES.

Trisodium phosphate and caustic soda are strong alkalies. The hardness buffer and titrating solution contain a strong alkali. These chemicals shall never be handled directly. When measuring trisodium phosphate for boiler water treatment use a scoop, not hands. Caustic soda must be dissolved in cold feedwater because it generates heat when dissolving. Disodium phosphate, trisodium EDTA, morpholine, and sodium nitrite are weak alkalies. The chemicals inside the dissolved oxygen ampoules are also alkalies. Do not mix alkalies directly with acids. If alkalies contact the skin, flush the affected skin area with cold water until the slippery feeling disappears. If a burning or itching sensation persists, seek medical attention. If alkali comes in contact with the eyes, flush with large amounts of potable water and obtain immediate medical treatment. All alkalies must be stored separately from acids.

220-25.5 FLAMMABLES.

The flashpoint of 40 percent morpholine is 82.2°C (180°F) (open cup). The flashpoint of isopropyl alcohol is 15°C (59°F). Stow these materials in accordance with **NSTM Chapter 670** .

220-25.6 POISONS.

All of the test and treatment chemicals are poisons having varying degrees of toxicity. Isopropyl alcohol is very different from ethyl alcohol. Small amounts of isopropyl alcohol, if swallowed, can cause serious illness. Mercuric nitrate is a poison which can cause ill effects whether exposure is chronic (small doses over a long period of time) or acute (large doses over a short period of time). Silica-1 and amino acid reagents are also poisons. Avoid mixing the hardness buffer reagents with acids since toxic hydrogen sulfide gas will be generated.

Table 220-25-1 CHEMICAL CLASSIFICATION AND SAFETY PRECAUTIONS

Chemical	**Class**	**Stock Concentration**	**Use Concentration***	**Precaution**
Amino Acid Reagent	Acid & Poison	100%	100%	c
Caustic Soda	Alkali	97%	8%	a
Chloride Indicator	Poison	100%	0.5%	b,c,e

Table 220-25-1 CHEMICAL CLASSIFICATION AND SAFETY PRECAUTIONS - Continued

Chemical	Class	Stock Concentration	Use Concentration*	Precaution
Dissolved Oxygen Ampoule	Alkali	1%	1%	a
Hardness Buffer	Alkali & Poison	<10%	<10%	a,b,c
Hardness Titrating Solution	Alkali	0.4%	0.4%	a
Hydrazine	Poison	7.0%	0.2%	a,b,c,d
Hydrazine Ampoules	Acid	6.5%	6.5%	a
Isopropyl Alcohol	Poison	99%	99%	b,c
Mercuric Nitrate	Acid & Poison	0.5 N	0.01 N	a,c
Methyl Purple Indicator	Poison	100%	0.2%	b,c,e
Morpholine	Alkali	40%	40%	a,b,d
Nitric Acid	Acid	1.0 N	0.05 N	a
Phenolphthalein	Poison	100%	1%	c
Silica One Reagent	Acid & Poison	15%	15%	a,c
Trisodium Phosphate Dodecahydrate	Alkali	97%	8%	a

*Designates concentration of chemical that results when the chemical is dissolved or diluted for use in testing or treatment.

Precaution Key:

a. Causes burns to skin and eyes. Avoid contact with eyes, skin and clothing. In case of contact, flush skin with large amounts of water; for eyes, flush with potable water for at least 15 minutes. Obtain medical attention (if swallowed or in eyes).

b. Do not breathe vapor. Use in well ventilated area.

c. Obtain medical attention if swallowed.

d. Direct contact between steam and food products is prohibited.

e. Hazard is due to isopropyl alcohol that is used to dissolve dry chemicals.

220-25.7 SEVEN PERCENT HYDRAZINE SOLUTION.

Seven percent (7%) hydrazine solution is alkaline, volatile and toxic. Harmful, possibly fatal, effects may result from ingestion, inhalation of vapor, or prolonged contact with the skin. These effects include dizziness, nausea, hoarseness, headache and dermatitis. When inhaled, it may cause acute and chronic disease of the lungs, liver, kidneys and central nervous system. Both inhalation or contact with skin must be avoided. In certain species of animals, hydrazine has been identified as a carcinogen (cancer causing agent). Therefore, it is considered to be a suspect human carcinogen. The American Conference of Governmental Industrial Hygienists has set limits for airborne concentrations of toxic materials. These limits are referred to as Threshold Limit Values (TLV). They are time weighted averages for a 40 hour work week. For hydrazine the TLV in air is 0.1 ppm by volume. The enclosed transfer system eliminates potential for hydrazine exposure. Monitoring of hydrazine levels during simulated spill testing have shown that the airborne hydrazine concentration to be below the TLV; therefore, respiratory protection is not required even during spill clean up.

220-25.8 Compatibility.

Stock hydrazine solution is a strong reducing agent and shall not be allowed to contact oxidizing agents such as chlorine, bromine, nitrites or hypochlorites. Hydrazine, being alkaline, shall not be allowed to contact acids. Hydrazine is also incompatible with many organic materials. Stainless steel and high density polyethylene are the only materials suitable for prolonged contact with the stock solution.

220-25.9 Storage.

Hydrazine should only be installed in the cabinet provided as part of the injection system. This cabinet shall be labeled ″Hydrazine storage only.″ Hydrazine stock solution is carried as packaged to the hydrazine storage cabinet. The bottle is removed from the box at the cabinet and immediately placed in storage. No other material is to be stored in the hydrazine storage cabinet. Stock hydrazine shall always be stored upright. The storage cabinet has been designed and constructed in accordance with National Fire Protection Association Code #30 in that internal temperature will not exceed 325°F when subjected to a 10 minute fire test. The stock hydrazine is not flammable. The cabinet has been provided to protect the bottles during a fire. The cabinet door, if open, will close automatically in the event of fire in the space. The cabinet shall be kept locked. Stock hydrazine solution shall be kept from freezing, from contact with heated surfaces and shall not be stored in direct sunlight. The storage cabinet shall be maintained full at all times by returning empty bottle to the cabinet. This is required to prevent shifting or tipping of full bottles. Empty bottles must be disposed ashore as plastic waste.

220-25.10 Safety Equipment.

A shower/eyewash shall be located within 10 feet of the injection system. A storage locker labeled ″Hydrazine Safety Equipment″ shall be located near the injection equipment and shall contain the following:

SAFETY EQUIPMENT

Item	Quantity
Apron, toxicological	2
Drum, shipping and storage	1
Foot wear covers, chemical protective	2
Gloves, chemical protective	2
Goggles, chemical safety	2
Plastic bag	1
Spill absorbent	1

220-25.11 Safety Procedures.

The operators shall wear chemical protective gloves, a face shield, chemical safety goggles, a toxicological apron, and coveralls when introducing 7% hydrazine solution into the piercing apparatus. In case of eye contact with stock hydrazine or treatment solution, immediately flush at eye wash station for a minimum of 15 minutes, lifting upper and lower eyelids occasionally. Seek medical attention. Skin areas affected by either stock solution or treatment solution shall be flushed immediately with cold water for 15 minutes. Seek medical attention if skin feels itchy or slippery. Immediately remove any clothes that have been contaminated with the stock or treatment solution, launder before wearing again. After each use, rinse the protective gear with water. Wash face and hands with soap and water. Protective gear is not required to be worn when onloading new supplies of hydrazine solution. Engineering personnel involved with handling hydrazine, including the spill clean up team, shall review the ″Spill Cleanup and Preparation/Injection of Treatment/Layup Solution″ video yearly.

220-25.12 SPILL CLEAN UP PROCEDURES FOR STOCK HYDRAZINE

WARNING

Wear face shield, goggles, gloves, boots, coveralls, and apron during spill clean up. Never use rags or paper to wipe up spills as heat may be generated.

220-25.13

Spill in area that cannot be flushed to bilge or directly overboard.

1. Clear personnel from area.
2. Spread spill absorbent (NSN 9Q 7930-00-269-1272) over spill until entire spill is covered.
3. Sweep absorbent up with a broom and a metal dust pan. Place absorbent in a plastic bag (NSN 9Q 8105-00-200-0195). Rinse broom and pan with water.
4. Place bag in a metal drum (NSN 9Q 8110-00-254-5713) and seal. Label the drum, ″Caution: Contains Hydrazine Waste″. The drum shall be turned in to the Public Works Officer or Public Works Center at any shipyard or other Navy industrial facility.
5. Mop deck area and dispose of clean up solution.
6. Refer to paragraph 220-25.15 for disposal of hydrazine bottle.

220-25.14

Spill in area that can be flushed to bilge or directly overboard.

1. Clear personnel from area.
2. Have space ventilation on maximum.
3. Flush to bilge or directly overboard. Personnel shall not be permitted to enter bilge until waste water has been disposed.
4. Refer to paragraph 220-25.15 for disposal of hydrazine bottle.

220-25.15 LEAKAGE OF STOCK HYDRAZINE BOTTLE.

If upon opening shipping carton, fluid is observed inside plastic bag, then the bottle is assumed to be leaking. The procedure for disposal of leaking hydrazine bottle is:

1. Clear personnel from area.
2. Have space ventilation on maximum.
3. Wear goggles, face shield, coveralls, gloves, boots and apron.
4. Carefully remove bottle from the bag under stream of water. Once the bottle exterior has been thoroughly flushed, place the bottle immediately in the piercing apparatus. If the mixing tank contains treatment solution,

drain the solution to the bilge. Drain and flush the bottle following the procedure for preparation of treatment solution. Personnel shall not be permitted to enter bilge area until waste has been disposed.

5. Drain the tank to the bilge.

220-25.16 LEAKAGE OF TREATMENT SOLUTION.

The procedure for repairing a leak of treatment solution from the continuous treatment system is:

1. Clear personnel from the area.
2. Secure nitrogen valve, hydrazine supply to DFT cutout valve and hydrazine supply to control panel cutout valve.
3. Wear face shield, goggles, gloves, boots and apron.
4. Identify source of leak.
5. Open vent valve to relieve nitrogen pressure.
6. Drain treatment solution to the bilge and flush system with condensate. Personnel shall not be permitted to enter bilge area until waste has been disposed.
7. Flush area of leak thoroughly with water.
8. Repair or replace leaking component.
9. Fill system with condensate and pressure test using nitrogen pressure to 90 psig.

220-25.17 GENERAL HANDLING PROCEDURES

220-25.18

Test Chemicals. Goggles and plastic or rubber gloves shall be worn when pouring nitric acid stock solution, mercuric nitrate stock solution, and hardness titrating solution. A face shield, goggles, apron, and plastic or rubber gloves are worn to prepare dilute caustic soda.

220-25.19

Treatment Chemicals. A face shield shall be worn when mixing treatment chemicals to prevent contact with alkaline treatment solutions. A face shield is worn when treating the boiler because of the possibility of hot feedwater spraying back on the operator should an error or equipment malfunction occur. A face shield, goggles, apron, and plastic or rubber gloves shall be worn when handling caustic soda or morpholine solution. When handling hydrazine, refer to paragraph 220-25.11.

220-25.20

Sampling. Wear a face shield when obtaining a deaerated feedwater or a boiler water sample; wear a finger cot or surgical glove during dissolved oxygen testing; and wear a surgical glove during hydrazine testing to protect against the acid in the ampoule.

220-25.21 ION EXCHANGE RESIN

220-25.22

Ion exchange resin should be stored in a space where the temperature is between 0°C (32°F) and 38°C (100°F). If the resin freezes and then thaws, resin beads may crack. Fragmented beads produce compaction of the resin when used in the demineralizer, therefore restricting flow. Resin bead particles may also pass through the retention screen of the demineralizer. Extreme heat will cause the resin to lose exchange capacity and possibly melt. Reserve feedwater used with the demineralizer should be less than 60°C (140°F).

220-25.23

Resin is supplied in double polyethylene bags to ensure that the resin remains moist. When charged with resin, the demineralizer tank should be kept completely filled with water to prevent drying of the resin. Dry resin which is subsequently wet experiences mechanical shock which can cause cracking. When filling the demineralizer with resin, the tank should have no standing water; otherwise, the resin will classify (anion resin separates from cation resin) reducing flow and efficiency.

SECTION 26.

FEEDWATER AND BOILER WATER SAMPLING AND TESTING

220-26.1 PURPOSE

220-26.2

Effective shipboard treatment of both feedwater and boiler water is based on the accurate performance and interpretation of the tests that determine water quality. If these tests are not performed accurately, the water will not be treated properly; therefore, scale formation, carryover, and excessive corrosion will occur. Instructions for the interpretation of the test results and corrective action to be taken are specified in other sections, but will be of little benefit if the instructions for sampling and testing in this section are not carefully followed.

220-26.3 FEEDWATER/CONDENSATE SYSTEM SAMPLING

220-26.4

Feedwater/condensate system samples, taken to be tested for chloride and hardness, shall be cooled below 38°C (100°F). Dissolved oxygen and hydrazine sample temperature requirements are given in the specific test procedures. The equipment required for all of the sampling and testing except salinity/conductivity indicators is listed in Section 28. A separate sample bottle shall be designated for each feed tank, DFT, condenser, drain tank, evaporator distillate, and drain source.

220-26.5 RESERVE FEEDWATER.

Reserve feedwater is sampled for chloride (paragraph 220-26.17) and hardness (paragraph 220-26.18).

220-26.6 Thief Sampling.

The procedure for reserve feedwater thief sampling is as follows:

1. Remove the sounding tube cap and insert the thief sampler letting it fall to the bottom of the tube.
2. Draw two samples as in step 1 and rinse the plastic quart sample bottle and cap.
3. Draw additional samples as required to fill the sample bottle.
4. Cap the sample bottle.
5. Replace the sounding tube cap and ensure that it is set properly.
6. Enter the time of sampling in the appropriate log.

220-26.7 Level Indicating and Pump Petcocks.

The sampling procedure for reserve feedwater using level indicating and pump petcocks is as follows:

1. With the pump running, initiate a flow of feedwater from one of the petcocks.
2. Flush the line for 30 seconds.
3. Rinse the plastic quart sample bottle and cap with sample.
4. Obtain a full quart of the sample and cap the bottle.
5. Secure the pump.
6. Secure the petcock.
7. Enter the time of sampling in the appropriate log.

220-26.8 DEAERATED FEEDWATER.

The water in the deaerating feed tank (DFT) is sampled for hydrazine, chloride (paragraph 220-26.17), and dissolved oxygen (paragraph 220-26.19).

220-26.9 DFT Sampling for Chloride and Hardness.

The sampling procedure is as follows:

WARNING

A face shield shall be worn when sampling the water in the DFT.

1. Establish full coolant flow through the cooler.
2. Open the sample outlet valves 1/2 turn.
3. Fully open the sample inlet valves in sequence from the cooler to the DFT.
4. When the sample flashes to steam or the sample has flowed for 5 minutes, throttle the sample line outlet valve until the sample flow is at a temperature less than 38°C (100°F).
5. Rinse the plastic sample bottle and cap several times with the sample water.

6. Collect a full bottle of sample and immediately cap the bottle.
7. Close the sample line inlet valves from the DFT to the cooler.
8. Close the sample line outlet valve.
9. Secure the cooling water.
10. Enter the time of sampling in the appropriate log.

220-26.10 DFT Sampling for the Dissolved Oxygen and Hydrazine Tests.

Because the dissolved oxygen level of deaerated feedwater is determined during sampling, both the sampling and test procedure are included in paragraph 220-26.19. Normally sampling for hydrazine follows dissolved oxygen testing. Both sampling and test procedures are included in the paragraph.

220-26.11 MAKEUP FEEDWATER-CONDENSATE-DRAINS.

These various feed system waters are tested for chloride (paragraph 220-26.17) and, when necessary, hardness (paragraph 220-26.18) in order to check the operation of salinity/conductivity indicators. The sampling procedure for midstream sampling of feedwater system components is as follows:

1. Locate and open the sampling connection or petcock.
2. Flush the line for 15 seconds.
3. Rinse the plastic quart sampling bottle and cap with sample water.
4. Obtain a full quart sample, cap the bottle, and secure the sampling connection or petcock.
5. Enter the time of sampling in the appropriate log.

220-26.12 AUTOMATIC SAMPLING.

Automatic feedwater sampling is accomplished by monitoring the quality of a flowing stream with a salinity/conductivity indicator (paragraph 220-26.22) or conductivity cell (paragraph 220-26.23). This type of sampling is instantaneous and is generally not subject to outside contamination. The main requirements of this type of sampling are that the cell be located in a flowing stream and be properly maintained.

220-26.13 SHORE SOURCE FEEDWATER.

Shore source feedwater is supplied by tank truck or by a demineralizer unit utilizing mixed bed ion exchange resin. A sample of feedwater supplied by a tank truck may be obtained at the tank's discharge line. Feedwater supplied by a demineralizer may be sampled from a test cock on the demineralizer unit. Prior to sampling, the demineralizer shall be flushed. After flushing, sample the flowing effluent (see paragraph 220-26.23). The sample bottle and all sample lines shall be thoroughly flushed prior to obtaining a sample. Plastic (polyethylene) bottles shall be used for sampling since glass can cause high silica results.

220-26.14 SHORE STEAM.

The sampling of shore steam requires that the steam be condensed. A rainmaker may be employed or the condensate from a steam trap may be used if available. Thoroughly flush all lines and the plastic container and cap before drawing a sample for testing. The samples are analyzed for pH (paragraph 220-26.21), hardness (paragraph 220-26.18) conductivity (paragraph 220-26.30) and silica (paragraph 220-26.24). The activity providing the shore source steam is responsible for conducting pH, conductivity, hardness and silica tests and providing the ship with the test results. Refer to paragraphs 220-22.18 and 220-22.21.

220-26.15 DESUPERHEATER STEAM.

Ships of recent construction have a desuperheater sample cooler installed in a line connected to the main boiler's desuperheater outlet in accordance with NAVSEA dwg 803-1385735. Sampling procedures are the same as those given for boiler water (paragraph 220-26.26).

220-26.16 FEEDWATER TESTS

220-26.17 FEEDWATER CHLORIDE TEST.

The amount of chloride in feedwater is determined by measuring a 100 ml sample, adding chloride indicator, titrating with nitric acid until the sample turns yellow, adding 1.0 ml of nitric acid in excess, then titrating with mercuric nitrate solution until the sample turns a pale blue-violet. The buret reading multiplied by 0.1 gives the chloride result in epm.

1. Apparatus
   a. Nitric acid reagent bottle and buret assembly.
   b. Mercuric nitrate reagent bottle and buret assembly.
   c. Casserole.
   d. Stirring rod.
   e. Graduated cylinder, 100 ml.
2. Reagents
   a. Chloride indicator (contents of one chloride indicator capsule dissolved in 50 ml of isopropyl alcohol, refer to paragraph 220-24.51).
   b. Nitric acid reagent 0.05 N (prepared from 50 ml of 1.0 N nitric acid stock solution diluted to 1,000 ml with distilled water, refer to paragraph 220-24.47).
   c. Mercuric nitrate reagent, 0.01 N (prepared from 20 ml of 0.5 N mercuric nitrate diluted to 1,000 ml with distilled water, refer to paragraph 220-24.48).
   d. Distilled water.
3. Interferences
   a. A large excess of nitric acid causes a high result.
   b. Colored water or suspended matter in the sample may interfere in detecting the indicator color change.
   c. A large excess of sodium nitrite will make the end point difficult to detect as well as cause false high results.
4. Procedure
   a. Rinse the casserole and stirring rod with distilled water.
   b. Rinse a 100 ml graduated cylinder with distilled water and then with some of the sample water.
   c. Measure 100 ml of the sample into the graduated cylinder and pour the 100 ml into the casserole.
   d. Add 4 to 6 drops of chloride indicator to the sample in the casserole. The color of the sample will be pale blue-violet or red.

e. Zero the buret and add nitric acid reagent, 1 drop at a time while stirring, until the sample becomes yellow.

f. Add exactly 1.0 ml more of nitric acid reagent to the sample.

g. Fill the mercuric nitrate buret and zero; be sure the buret tip is filled with liquid.

h. Add mercuric nitrate reagent to the sample 1 drop at a time, while stirring, until the yellow color disappears and is replaced by the first pale violet persisting throughout the sample.

i. Read the buret to the nearest 0.1 ml, record the buret reading, multiply the reading by 0.1 and record the result in epm chloride. For example, for a buret reading of 0.2 ml, the chloride concentration is calculated as follows:

0.2 ml x 0.1 = 0.02 epm chloride

j. Pour the sample containing the chemicals used for the test and the first rinse into a plastic 5-gallon bottle identified as containing mercury wastes.

WARNING

Bottles containing used mercuric nitrate should be turned in to the ship's hazardous material coordinator.

5. Range of Error: the range of error of the test is ± 0.01 epm chloride.

220-26.18 FEEDWATER HARDNESS TEST.

The hardness test is performed by measuring a 100 ml sample, adding 1/2 a dipper of dimethylglyoxime, 2 dippers of buffer, then 2 dippers of indicator, and titrating to a blue end point. The buret reading multiplied by 0.2 gives the hardness result in epm.

1. Apparatus
   a. Squeezomatic buret assembly.
   b. Brass dippers (3).
   c. Casserole.
   d. Stirring rod.
   e. Graduated cylinder, 100 ml.

2. Reagents
   a. Hardness Buffer. The white buffer powder contains potassium hydroxide, sodium sulfide, and sodium tetraborate in an inert filler. Potassium hydroxide is similar to caustic soda. Sodium sulfide is toxic (rotten egg odor). Avoid inhalation of buffer dust and store separately from acids.
   b. Hardness Indicator. The dark indicator crystals contain Eriochrome Black T in an inert filler.
   c. Hardness Titrating Solution. (1 ml = 1 mg $CaCO_3$). The reagent is an alkaline solution of ethylenediaminetetraacetate (EDTA).
   d. Dimethylglyoxime (DMG). The DMG crystals are used to eliminate nickel interference.

3. Interferences
   a. Nickel at a level of 0.1 ppm or greater interferes with the color change unless DMG is added. The sample will change from red to purple, but then will not change to blue. In some instances, nickel may cause a problem in shipboard analyses for evaporator distillate; therefore, DMG has been supplied to eliminate

nickel interference. The addition of DMG is actually necessary only if difficulty is experienced in end-point detection, but is added to all samples for procedural uniformity.

b. Colored water or suspended matter in the sample may interfere in detecting color changes.

c. Copper and dissolved gases (bicarbonate) interfere with the titration color change to give false high hardness results, especially for evaporator distillate and distiller air ejector drains. The sample will be gray instead of the normal sky blue color and further additions of hardness titrating solution will not change the sample color. Hardness greater than 0.5 epm without high chemical chloride should be suspected as being falsely high. If false high hardness is suspected, reversing the order of chemical reagent addition will sometimes minimize the interference; add hardness buffer, DMG and then the hardness indicator.

4. Procedure

NOTE

Keep the dippers for buffer, indicator, and DMG dry when in use. Do not interchange the dippers when running a series of hardness tests, because this will result in contaminating the reagents. Dippers should be rinsed with distilled water and shaken dry when testing is completed.

a. Rinse the casserole and stirring rod with distilled water.

b. Rinse the 100 ml graduated cylinder with distilled water and then with the sample. Measure 100 ml of sample into the graduated cylinder and pour the sample into the casserole.

c. Add 1/2 dipper of DMG crystals and stir. Most of the DMG will not dissolve, but will float in the sample.

d. Add 2 level dippers of hardness buffer and stir until dissolved.

e. Add 2 level dippers of hardness indicator and stir until dissolved.

f. If the sample is sky blue, report zero epm hardness.

g. If the sample is purple or red, zero the buret. Slowly add titrating solution dropwise, while stirring, until a sky-blue end point is reached.

h. Read the buret to the nearest 0.1 ml, record the buret reading as required, multiply the reading by 0.2, and record the result in epm hardness. For example, for a buret reading of 0.2 ml, the hardness is calculated as follows:

   0.2 ml x 0.2 = 0.04 epm hardness

i. After completion of the hardness test, thoroughly rinse the casserole and stirring rod with tap water and then with distilled water. (A tap water rinse is used because the hardness buffer is difficult to flush from the casserole. The distilled water then rinses away the tap water.)

5. Range of Error: the range of error of the test is ± 0.02 epm hardness.

220-26.19 DISSOLVED OXYGEN TEST.

In this test a flow of deaerated feedwater is started through the sampling apparatus, the line is flushed, and the temperature adjusted. An ampoule containing the test chemicals is inserted, the tip broken, the sample mixed and then inserted into a comparator. The dissolved oxygen result in parts per billion is read from the comparator.

WARNING

Wear a face shield when obtaining a dissolved oxygen sample.

1. Apparatus
   a. Chain clamp.
   b. Utility clamp.
   c. Rubber tubing.
   d. Glass sampler.
   e. Plastic snapper.
   f. Thermometer (0°C to 100°C) (32°F to 212°F).
   g. Finger cot or surgical glove.
   h. Comparator 0-40 ppb 0_2 .
2. Reagents
   a. Ampoule. An ampoule containing the needed reagents is supplied.
3. Interferences
   a. Colored water or suspended matter in the sample may interfere in detecting comparator color differences.
   b. Sample will absorb atmospheric oxygen. Test must be run immediately after breaking ampoule tip.
4. Procedure
   a. Attach one end of a short length of black neoprene rubber tubing to the outlet nipple of the sample cooler.
   b. Attach the glass sampling tube to the other end of the rubber tubing and secure the glass tube upright with the utility clamp. The utility clamp and the chain clamp should be permanently attached near the sample cooler.
   c. With the cooling water flow secured (see NOTE), start a flow of sample water at a maximum rate to flush the sample system.

NOTE

When the sample cooler uses seawater or drinking water as a coolant, close the cooling water inlet valve to the cooler in preparation for hot flushing. To preclude cooler rupture during hot flushing, a cooling water outlet valve has not been installed in these systems.

NOTE

When the sample cooler uses chilled water from the air-conditioning main as coolant, close only the cooling water outlet valve for the sample cooler in preparation for hot flushing. Cooling water flow should be controlled by the cooling water outlet valve only. All other cooling water valves remain open.

   d. Initiate coolant flow to flush the line with sample flow at a temperature of 60°C (140°F) to 93°C (200°F) for at least 5 minutes. Knead the rubber tubing to dislodge air bubbles.

e. Adjust cooling water and sample flow rate to obtain a temperature of between 21°C (70°F) and 38°C (100°F) as measured by a thermometer.
f. Place the snapper in the sampling tube.
g. Place an ampoule in the snapper. Sample flow must be sufficient to float the ampoule without forcing it out of the snapper. Hold the ampoule down for 1 minute.
h. Press down on the ampoule to break the tip. A sample will be drawn in and a small bubble of inert gas will remain in the ampoule.
i. Remove the ampoule from the snapper, immediately cover the open end with a finger (the finger should be protected with a finger cot or surgical glove), and invert the ampoule 10 times allowing the gas bubble to transverse the tube to mix reagent and sample.
j. Wipe the ampoule dry and place it in the center of the comparator, with the open end up.
k. View the comparator from the bottom with the top pointing at a daylight fluorescent lamp.
l. Rotate the comparator until a color match is obtained or the sample color lies between two of the standard colors or the sample color is darker than the 40 ppb standard.
   (1) If a color match is obtained, record that value in the log.
   (2) If the color lies between the two standard colors, add the two values, divide by two, and record that value in the log.
   (3) If the color of the sample is darker than the 40 ppb standard, record greater than 40 ppb in the log.
m. Dispose of the used ampoule in such a manner that the broken glass does not present a safety hazard to personnel.
n. After finishing the test, secure the feedwater flow, secure the coolant and disconnect the rubber tubing and sampling tube.

5. Range of Error: the range of error of the test is ± 2.5 ppb dissolved oxygen.

220-26.20 FEEDWATER HYDRAZINE TEST.

This test is accomplished following the dissolved oxygen test or independently by starting a flow of deaerated feedwater through the sample apparatus, the line is flushed and the temperature is adjusted. The hydrazine test uses a disposable reagent containing ampoule. Sample is drawn into the ampoule and a yellow color develops that is proportional to the hydrazine concentration. The hydrazine result in parts per billion is read from the low range comparator.

WARNING

Wear a face shield and surgical gloves when obtaining a hydrazine sample.

1. Apparatus
   a. Chain clamp.
   b. Utility clamp.
   c. Rubber tubing.
   d. Glass sampler.
   e. Plastic snapper.

f. Thermometer (0°C to 100°C)(32 to 212°F).

g. Low range comparator (0 to 500 ppb).

h. Surgical gloves.

2. Reagents

a. Ampoule. The required reagents are contained in the ampoule.

3. Interferences

a. Color or suspended matter in sample may interfere in detecting comparator color differences.

b. Absorption of atmospheric oxygen by sample causes hydrazine level to decrease.

4. Procedure

NOTE

The hydrazine test uses the same sampling apparatus as the feedwater dissolved oxygen test. If the hydrazine test is done immediately following the dissolved oxygen test, start at step h and wear surgical glove for both tests.

a. Attach rubber tubing to outlet of sample cooler.

b. Attach glass sampler to end of rubber tubing and secure upright in utility clamp.

c. Establish full coolant flow.

d. Open sample outlet valves.

e. Fully open sample inlet valves from cooler to DFT.

f. When sample flashes to steam or has flowed for 5 minutes, throttle sample line outlet valve until sample flow is at a temperature less than 38°C (100°F).

CAUTION

Wear surgical glove to protect hand.

g. Place snapper in sampler.

h. Place an ampoule in snapper. Sample flow must be sufficient to float ampoule without forcing it out of snapper.

i. Press down on ampoule to break tip.

j. Remove ampoule, and invert 10 times allowing gas bubble to transverse tube to mix reagent and sample.

k. Wait 10 minutes for color to fully develop.

l. Wipe ampoule dry and place in center of low range comparator, with open end up.

m. View the comparator from bottom with top pointing at a daylight fluorescent lamp.

n. Rotate comparator to compare ampoule to standard colors:

(1) If a color match is obtained, record that value.

(2) If color lies between two standards, record average.

(3) If color is darker than the 500 ppb standard, record greater than 500 ppb.

o. Dispose of used ampoule in such a manner that broken glass does not present a safety hazard to personnel.

p. After finishing test, secure feedwater flow, secure coolant and disconnect rubber tubing and sampling tube.

5. Range of Error: The range of error of the test varies, within the feedwater limits it is ± 10 ppb.

220-26.21 FEEDWATER pH TEST FOR SHORE SOURCE FEEDWATER OR SHORE STEAM CONDENSATE.

Phenolphthalein indicator is added to a 50 ml sample and the color is observed. Methyl purple indicator is added to another 50 ml sample and the color is observed. This test indicates whether the feedwater pH is satisfactory.

NOTE

If necessary, adjust sample temperature to 25°C ± 3°C (77°F ± 5°F). Minimize exposure of the sample to the atmosphere.

1. Apparatus
   a. Casserole.
   b. Stirring rod.
   c. Graduated cylinder, 100 ml.
2. Reagents
   a. Phenolphthalein indicator (2 level dippers of phenolphthalein dissolved in 25 ml of distilled water and 25 ml of isopropyl alcohol - refer to paragraph 220-24.49).
   b. Methyl purple indicator (the contents of 1 methyl purple indicator capsule dissolved in 50 ml of distilled water, plus 10 ml isopropyl alcohol - refer to paragraph 220-24.50).
   c. Distilled water.
3. Interferences
   a. Absorption of carbon dioxide from the atmosphere lowers pH. Refer to paragraph 220-31.203.
4. Procedure
   a. Rinse the casserole and stirring rod with distilled water.
   b. Rinse the graduated cylinder with distilled water and then with some of the water to be tested.
   c. Measure 50 ml of sample into the casserole.
   d. Add 2-3 drops of phenolphthalein indicator to the sample water.
      (1) If the sample is pink, record the pH result as greater than 8.2 (>8.2). The test is complete.
      (2) If the sample is clear, continue with step e.
   e. Add 2-3 drops of methyl purple indicator to the sample.
      (1) If the sample is green, record the pH result as 5.4-8.2.
      (2) If the sample is purple, record the pH result as less than 5.4 (<5.4).

220-26.22 SALINITY/CONDUCTIVITY INDICATOR TESTING.

Salinity/conductivity indicator testing is accomplished as follows:

1. Set the temperature compensator to the value of the temperature of the solution being measured.

NOTE

Some salinity/conductivity indicators have automatic temperature compensator devices installed.

2. Directly read the indicator meter.

NOTE

Normally, the salinity/conductivity indicator reads out in epm of chloride. The meter reading shall be interpolated to the nearest 0.005 epm. Some indicators may read out in grains per gallon (gpg) sea salt. To convert gpg to epm of chloride, multiply the gpg by a factor of 0.261. To convert ppm chloride to epm chloride, divide the ppm by a factor of 35.5. To convert µmho/cm to epm chloride, divide µmho/cm by 145.

3. Record the test result in the appropriate log.

220-26.23 CONDUCTIVITY METER TESTING (DEMINERALIZERS).

Conductivity meters are equipped with automatic temperature compensators.

1. Directly read the indicator meter.

NOTE

The conductivity meter reads out in micromhos per centimeter (µmho/cm).

2. Record the test result in the appropriate log.

220-26.24 SILICA TEST FOR SHORE SOURCE FEEDWATER AND STEAM CONDENSATE.

This silica test is performed by measuring 10 ml of sample and adding Silica-1 Reagent, citric acid and amino acid. Specific time intervals are observed between each step to allow the chemical reactions to take place. The colorimeter is standardized by using 10 ml of original sample water. The treated sample is then placed in the colorimeter and silica results are read directly in ppm.

1. Apparatus
   a. Colorimeter.
   b. Sample cells (2).
   c. Cell holder.
   d. Clippers.
2. Reagents
   a. Silica-1 Reagent (Sodium Molybdate). Contains sodium molybdate dissolved in sulfuric acid. Sodium molybdate is toxic. Since sulfuric acid is an acid, store the reagent separately from alkalies.
   b. Citric Acid. Store citric acid separately from alkalies.
   c. Amino Acid. Contains 1-amino-2-naphthol-4-sulfonic acid, sodium sulfite and sodium bisulfite. Sodium sulfite and sodium bisulfite are toxic. 1-amino-2-naphthol- 4-sulfonic acid is an acid. Store separately from alkalies.

3. Interferences
   a. Large amounts of phosphate. This will not normally be encountered in the type of samples being analyzed for silica with this test.
   b. Colored water or suspended matter in the sample may cause high results. Using original sample water for standardizing the colorimeter helps minimize this type of interference.
   c. Dirty sample cells can interfere. Cells must be kept clean.
4. Procedure
   a. Rinse a clean sample cell and cap with sample. Fill the cell to the 10 ml mark with sample.
   b. Add exactly 14 drops of Silica-1 Reagent. Cap and swirl to mix. Wait 10 minutes.
   c. Using the clippers, clip the end off of a Citric Acid powder pillow. Add the contents of the pillow to the sample. Cap and swirl to mix. Wait 2 minutes.
   d. Add the contents of an Amino Acid powder pillow to the sample. Cap and swirl to mix. Wait at least 5 minutes but not more than 10 minutes before performing step h.
   e. Open the light shield on the colorimeter and place the cell holder in the sample well so that the white mark on the cell holder is pointing to the left set position. Press down firmly to seat it into place. Close the light shield.
   f. While holding the On button down, adjust the Left Set knob to align the meter needle with the arrow at the far left of the scale. Release the On button and remove the cell holder.
   g. Fill a clean sample cell to the 10 ml mark with original water sample. Wipe the outside of the cell until it is clean and dry. Cap and place the cell into the sample well. Press down firmly to set it into place. Close the light shield. While holding the On button down, adjust the Right Set knob until a reading of 0 mg/l is obtained. Release the On button and remove the sample cell.
   h. Wipe the outside of the treated sample cell until it is clean and dry. Place the treated sample (from step d) into the sample well. Press down firmly to set it into place. Close the light shield. Hold the On button down and allow the meter to stabilize (about 5 seconds). Record the reading in ppm silica. Remove treated sample from meter sample well and pour the sample containing the chemicals used for testing into a quart bottle identified as containing Silica-1 Reagent wastes.

WARNING

Bottles containing used Silica-1 Reagent should be turned in to the ship's hazardous material coordinator.

   i. Rinse sample cell with distilled water and wipe clean.
5. Range of Error: the range of error of the test is 0.04 ppm silica.

220-26.25 BOILER WATER SAMPLING

220-26.26

Boiler water sampling systems shall have a separate cooler for each boiler. Systems that share a cooler must be modified per applicable SHIPALT. The boiler water sample systems and cooler shall be in accordance with NAVSEA dwg 803-1385735. Boiler water shall be sampled at a temperature below 38°C (100°F) as measured by a thermometer. All of the equipment required for performing the tests is listed in Section 28. A separate sample bottle shall be designated for each boiler. The procedure for obtaining a representative boiler water sample on propulsion boilers using chelant treatment is given in Figure 220-22-6. The procedure for obtaining all other boiler water samples follows:

WARNING

Wear a face shield when obtaining a boiler water sample.

To prevent accidental cooler rupture, the cooling water inlet valves for sample coolers that have a closed loop coolant system shall be locked open.

1. Open cooling water valve and ensure coolant flow is established.
2. Open sample outlet valve.
3. Open sample cooler inlet valves in sequence from boiler to cooler.
4. When sample flashes to steam or has flowed for 5 minutes, throttle sample outlet valve until sample flow is less than 38°C (100°F).
5. Rinse sample bottle and cap several times with sample water.
6. Collect a full bottle of sample and immediately cap bottle.
7. Close sample valves starting at boiler.
8. Secure cooling water valve.

NOTE

In cases where the boilers are idle with a wet layup being applied and the boiler is under hydrostatic or nitrogen pressure, care must be exercised when sampling so that pressure is maintained. Otherwise, oxygen may contaminate the boiler water.

220-26.27 BOILER WATER TESTS

220-26.28 BOILER WATER ALKALINITY AND PHOSPHATE TEST (CHELANT TREATMENT).

The alkalinity and phosphate test is performed by adding phenolphthalein indicator to 200 ml of sample and titrating with nitric acid from pink to colorless. The buret reading divided by 4, gives the alkalinity value in epm. The nitric acid buret is zeroed, methyl purple indicator is added, and titration is continued from green to purple. This buret reading multiplied by 25, gives the phosphate value in ppm.

1. Apparatus
   a. Nitric acid reagent bottle and buret assembly.
   b. Casserole.
   c. Stirring rod.

d. Graduated cylinder, 100 ml.

2. Reagents

   a. Nitric acid reagent, 0.05 N (prepared from 50 ml of 1.0 N nitric acid stock solution diluted to 1,000 ml with distilled water, refer to paragraph 220-24.47).

   b. Phenolphthalein indicator (2 level dippers of phenolphthalein dissolved in 25 ml of distilled water and 25 ml of isopropyl alcohol, refer to paragraph 220-24.49).

   c. Methyl purple indicator (contents of 1 methyl purple indicator capsule dissolved in 50 ml of distilled water plus 10 ml isopropyl alcohol, refer to paragraph 220-24.50).

   d. Dilute caustic soda (3 flakes or 2 dippers of bead form caustic soda is dissolved in 50 ml of distilled water, refer to paragraph 220-24.56). Dilute caustic soda solution is needed only if the alkalinity is zero epm.

3. Interferences

   a. Color or suspended matter in sample may interfere in detecting indicator color changes.

   b. Silica contamination may cause false high results.

   c. Excess morpholine following hydrazine layup will cause false high alkalinity and false high phosphate results.

   d. If caustic soda is added, sodium carbonate contamination of the caustic soda may cause false high phosphate results. See NOTE in paragraph 220-24.56.

   e. Bicarbonate in the sample may cause false high results. Samples exposed to air slowly absorb carbon dioxide, which converts to bicarbonate. Testing the sample within 30 minutes after sampling prevents absorption of carbon dioxide.

4. Procedure

   a. Rinse the casserole and stirring rod with distilled water.

   b. Rinse a 100 ml graduated cylinder with distilled water and then with some of the water to be tested.

   c. Measure exactly 200 ml of sample into the casserole.

   d. Add 2-3 drops of phenolphthalein indicator to the sample water. The sample should turn pink.

NOTE

If the sample does not turn pink, the alkalinity is 0 epm. Add dilute caustic soda 1 drop at a time until the sample turns pink. Proceed with step e., except record ″cs″ for ml phenolphthalein and 0 for alkalinity.

   e. Zero the nitric acid buret. Add nitric acid 1 drop at a time, while stirring, until pink color disappears completely. Read buret and record result in the ml phenolphthalein column. Divide reading by 4. This gives alkalinity of the water in epm. Record result in log.

   f. Add 2-3 drops of methyl purple indicator to sample water. Sample should turn green.

NOTE

If sample turns purple, phosphate is 0 ppm. Record 0 in the methyl purple column and in the phosphate column. The test is complete.

   g. Rezero the nitric acid buret. Add nitric acid one drop at a time, while stirring, until sample turns purple. A gray color will appear just before end point. Read buret and record result in the ml methyl purple column. Multiply reading by 25. This gives phosphate concentration in ppm. Record result.

5. Range of Error: The range of error of this test is ± 0.025 epm alkalinity and ± 2.5 ppm phosphate.

220-26.29 Feedwater Bicarbonate Test.

If shore source demineralized feedwater was received and boiler water alkalinity is increasing, the problem may be from shore demineralized feedwater. This test is provided as a troubleshooting test. If boiler water alkalinity is increasing rapidly for no apparent reason, check feedwater for bicarbonate. **The test is exactly the same as the boiler water phosphate test of paragraph 220-26.28** . Follow those procedures. Be sure the caustic soda solution is not contaminated, paragraph 220-24.56. If phosphate is greater than 5 ppm in feedwater, it is not phosphate that is being measured. It is bicarbonate, caused by exhaustion of the resin. Bicarbonate does not exist in boiler water because it decomposes. Interferences (high phosphate results) in the boiler water phosphate test are caused by silica or excess morpholine. Interferences (high phosphate results) in the phosphate test for condensate are caused by morpholine.

220-26.30 BOILER WATER CONDUCTIVITY TEST.

The conductivity test is performed by placing the conductivity cell in the boiler water sample, balancing the meter indicator, and reading the result on the meter dial.

1. Apparatus
   a. Meter, conductivity, SOLUBRIDGE, specific conductance of 40-8,000 μmho/cm; requires a 110-115 volt power supply.
   b. Cell, conductivity, dip type, 2.0 cell constant; connected to conductivity meter.
   c. Thermometer, metal, dial type, 0°C to 100°C
   d. Bottle, glass, square, 8 ounce.
2. Reagents
   a. Distilled water.
3. Interferences
   a. Oil and suspended matter may coat the electrode making it inoperable.
4. Procedure
   a. Rinse the conductivity cell, thermometer, and test bottle with distilled water and then with the sample.
   b. Place the cell and the thermometer in the test bottle. Add sufficient sample water to cover the air holes in the cell by 1/2 inch.
   c. Turn on the meter.
   d. Allow the older meters (Beckman Model RD-338) with the null tuning eye to warm up. The newer meters (Beckman Model SD-178) require no warm up.
   e. Adjust the meter temperature compensating dial to the temperature of the sample. Some meters have a temperature compensating dial marked in °F; in this case refer to Table 220-26-1 for conversion from °F to °C. Remove the thermometer and rinse it with distilled water.
   f. Move the cell up and down several times to remove entrapped air bubbles.
   g. Adjust the conductivity dial of the older meter until the null tuning eye deflects to the widest angle. Adjust the conductivity dial of the newer meter until the red and green lights are lit simultaneously or until one light goes off as the other comes on.
   h. Move the cell up and down. Readjust the conductivity dial if necessary. Repeat until there is no change in the reading.
   i. Read the conductivity value of the boiler water in μmho/cm. Record less than 40 μmho/cm as <40. Record the result in the log.

j. Turn the meter off.
k. Rinse the cell and the test bottle with distilled water. Store the cell in distilled water. The distilled water in the storage bottle is to be changed daily.

5. Range of Error: the range of error of the test is ± 3 percent.

220-26.31 BOILER WATER CHLORIDE TEST.

The amount of chloride in boiler water is determined by measuring a 25 ml sample, adding chloride indicator, titrating with nitric acid until the sample turns yellow, adding 1.0 ml of nitric acid in excess, and then titrating with mercuric nitrate until the sample turns a pale blue-violet. The buret reading multiplied by 0.4 gives the chloride result in epm.

1. Apparatus
   a. Nitric acid reagent bottle and buret assembly.
   b. Mercuric nitrate reagent bottle and buret assembly.
   c. Casserole.
   d. Stirring rod.
   e. Graduated cylinder, 100 ml.
2. Reagents
   a. Chloride indicator (contents of 1 chloride indicator capsule dissolved in 50 ml of isopropyl alcohol, refer to paragraph 220-24.51).
   b. Nitric acid reagent, 0.05 N (prepared from 50 ml of 1.0 N nitric acid stock solution diluted to 1,000 ml with distilled water, refer to paragraph 220-24.47).
   c. Mercuric nitrate reagent 0.01 N (prepared from 20 ml of 0.5 N mercuric nitrate diluted to 1,000 ml with distilled water, refer to paragraph 220-24.48).
   d. Distilled water.
3. Interferences
   a. A large excess of nitric acid causes a high result.
   b. Colored water or suspended matter in the sample may interfere in detecting the indicator color changes.
4. Procedure
   a. Rinse the casserole and stirring rod with distilled water.
   b. Rinse a 100 ml graduated cylinder with distilled water and then with some of the sample water.
   c. Measure 25 ml of the sample into the graduated cylinder and pour the 25 ml sample into the casserole.
   d. Add 4 to 6 drops of chloride indicator to the sample in the casserole. The color of the sample will be pale blue-violet to red depending upon the sample pH.
   e. Zero the buret and add nitric acid reagent, 1 drop at a time while stirring, until the sample passes through a pale blue-violet color and becomes yellow.
   f. Add exactly 1.0 ml more of nitric acid reagent to the sample.
   g. Fill the mercuric nitrate buret and drain to zero. Be sure the buret tip is filled with liquid.
   h. Add mercuric nitrate reagent, one drop at a time while stirring, until the yellow color disappears and is replaced by the first pale violet persisting throughout the sample.
   i. Read the buret and record the buret reading to the nearest 0.1 ml.

j. Multiply the buret reading by 0.4. This gives the chloride value in epm chloride. Record the result in the log. For example, if the buret reading is 1.7 ml, the chloride concentration is calculated as follows:

1.7 ml x 0.4 = 0.68 epm

k. Pour the sample containing the chemicals used for the test into a plastic 5-gallon bottle identified as containing mercury wastes.

WARNING

Bottles containing used mercuric nitrates should be turned in to the ship's hazardous material coordinator.

5. Range of Error: the range of error of the test is ± 0.04 epm chloride.

Table 220-26-1 TEMPERATURE CONVERSION CHART

°C	←→	°F	°C	←→	°F	°C	←→	°F
10	←→	50	37	←→	99	64	←→	147
11	←→	52	38	←→	100	65	←→	149
12	←→	54	39	←→	102	66	←→	151
13	←→	55	40	←→	104	67	←→	153
14	←→	57	41	←→	106	68	←→	154
15	←→	59	42	←→	108	69	←→	156
16	←→	61	43	←→	109	70	←→	158
17	←→	63	44	←→	111	71	←→	160
18	←→	64	45	←→	113	72	←→	162
19	←→	66	46	←→	115	73	←→	163
20	←→	68	47	←→	117	74	←→	165
21	←→	70	48	←→	118	75	←→	167
22	←→	72	49	←→	120	76	←→	169
23	←→	73	50	←→	122	77	←→	171
24	←→	75	51	←→	124	78	←→	172
25	←→	77	52	←→	126	79	←→	174
26	←→	79	53	←→	127	80	←→	176
27	←→	81	54	←→	129	81	←→	178
28	←→	82	55	←→	131	82	←→	180
29	←→	84	56	←→	133	83	←→	181
30	←→	86	57	←→	135	84	←→	183
31	←→	88	58	←→	136	85	←→	185
32	←→	90	59	←→	138	86	←→	187
33	←→	91	60	←→	140	87	←→	189
34	←→	93	61	←→	142	88	←→	190
35	←→	95	62	←→	144	89	←→	192
36	←→	97	63	←→	145	90	←→	194

220-26.32 BOILER WATER LAYUP HYDRAZINE TEST.

The hydrazine concentration of boiler water under layup is determined by placing a reagent containing ampoule in the sample. The ampoule tip is broken allowing sample to be drawn into the ampoule. A yellow color develops that is proportional to the hydrazine concentration. The hydrazine result in parts per million is read from the high range comparator.

WARNING

Wear surgical gloves when performing hydrazine test.

1. Apparatus
   a. Sample cup, 25 ml.
   b. High range comparator (0 to 100 ppm)
   c. Surgical gloves.
2. Reagents
   a. The required reagents are contained in the ampoule.
3. Interferences
   a. Color or suspended matter in sample may interfere in detecting comparator color differences.
   b. Absorption of atmospheric oxygen by sample causes hydrazine level to decrease.
4. Procedure
   a. Rinse sample cup with distilled water and then with sample.
   b. Fill sample cup with sample.
   c. Wearing surgical glove, place ampoule in cup with tip between side of cup and raised edge in bottom. Pull ampoule to side of cup to break tip.
   d. Remove ampoule, and invert 10 times allowing gas bubble to transverse tube to mix reagent and sample.
   e. Wait 10 minutes for color to fully develop.
   f. Wipe ampoule dry and compare to the high range comparator standard colors:
      (1) If a color match is obtained, record that value.
      (2) If color lies between two standards, record average.
      (3) If color is darker than the 100 ppm standard, record greater than 100 ppm.
   g. Dispose of used ampoule in such a manner that broken glass does not present a safety hazard to personnel.
5. Range of Error: The range of error of the test varies, within normal treatment range (20 to 100 ppm) is ±10 ppm.

220-26.33 SILICA TEST FOR BOILER WATER.

This silica test is performed by first measuring 10 ml of boiler water sample into a 100 ml plastic graduated cylinder and diluting to the 100 ml mark with distilled water. 10 ml of this diluted sample is then measured and Silica-1 Reagent, citric acid and amino acid are added, with specific time intervals being observed between each step to allow the chemical reactions to take place. The colorimeter is standardized using 10 ml of untreated diluted sample. The treated sample is then placed in the colorimeter. The colorimeter reading multiplied by 10 gives the silica result in ppm.

1. Apparatus
   a. Colorimeter.

b. Sample cells (2).

c. Cell holder.

d. Clippers.

e. Graduated cylinder, plastic, 100 ml.

2. Reagents

a. Silica-1 Reagent (sodium molybdate). Contains sodium molybdate dissolved in sulfuric acid. Sodium molybdate is toxic. Since sulfuric acid is an acid, store the reagent separately from alkalies.

b. Citric Acid. Store citric acid separately from alkalies.

c. Amino Acid. Contains 1-amino-2-naphthol-4-sulfonic acid, sodium sulfite and sodium bisulfite. Sodium sulfite and sodium bisulfite are toxic. 1-amino-2-naphthol- 4-sulfonic acid is an acid. Store separately from alkalies.

3. Interferences

a. Large amounts of phosphate can cause high results. This interference will be minimal unless boiler water phosphate levels are significantly above the upper limit.

b. Colored water or suspended matter in the sample may cause high results. Using diluted sample for standardizing the colorimeter helps minimize this type of interference.

c. Dirty sample cells can interfere. Cells must be kept clean.

d. If the distilled water used for diluting the sample contains silica, a false high boiler water silica result will be obtained. If there is any question, perform a feedwater silica test on a sample of the distilled water (paragraph 220-26.24), multiply the result by 10 and subtract from the boiler water silica result. Normally, seawater distillate from the evaporators is virtually free of silica.

4. Procedure

a. Rinse a clean plastic 100 ml graduated cylinder with sample. Measure 10 ml of sample into the graduated cylinder. Dilute to the 100 ml mark with distillate.

b. Rinse a clean sample cell and cap with diluted sample. Fill the cell to the 10 ml mark with diluted sample.

c. Add exactly 14 drops of Silica-1 Reagent. Cap and swirl to mix. Wait 10 minutes.

d. Using the clippers, clip the end off of a Citric Acid powder pillow. Add the contents of the pillow to the sample. Cap and swirl to mix. Wait 2 minutes.

e. Add the contents of an Amino Acid powder pillow to the sample. Cap and swirl to mix. Wait at least 5 minutes but not more than 10 minutes before performing step i.

f. Open the light shield on the colorimeter and place the cell holder in the sample well so that the white mark on the cell holder is pointing to the Left Set position. Press down firmly to seat it into place. Close the light shield.

g. While holding the On button down, adjust the Left Set knob to align the meter needle with the arrow at the far left of the scale. Release the On button and remove the cell holder.

h. Fill a clean sample cell to the 10 ml mark with diluted sample from the graduated cylinder. Wipe the outside of the cell until it is clean and dry. Cap and place the cell into the sample well. Press down firmly to set into place. Close the light shield. While holding the On button down, adjust the Right Set knob until a reading of 0 mg/l is obtained. Release the On button and remove the sample cell.

i. Wipe the outside of the treated sample cell until it is clean and dry. Place the treated sample (from step e.) into the sample well. Press down firmly to set it into place. Close the light shield. Hold the On button down and allow the meter to stabilize (about 5 seconds). Read the meter.

j. Multiply the meter reading by 10 to obtain the silica value in ppm. Record the result in the remarks section of the Boiler Water Chemistry Worksheet/Log. For example, if the meter reading is 0.62, silica concentration is calculated as follows:

   0.62 x 10 = 6.2 ppm silica

k. Remove treated sample from meter sample well and pour the sample containing the chemicals used for testing into a quart bottle identified as containing Silica-1 Reagent wastes.

WARNING

Bottles containing used Silica-1 Reagent should be turned in to the ship's hazardous material coordinator.

Rinse sample cell with distilled water and wipe clean.

5. Range of Error: the range of error of the test is ± 15%.

220-26.34 ALKALINITY STANDARD TEST

220-26.35

The test is performed by adding methyl purple to 50 ml of standard and titrating with nitric acid from green to purple.

1. Apparatus
   a. Nitric acid reagent bottle and buret assembly.
   b. Casserole.
   c. Stirring rod.
   d. Graduated cylinder, 100 ml.
2. Reagents
   a. Nitric acid reagent, 0.05N (prepared from 50 ml of 1.0N nitric acid stock solution diluted to 1,000 ml with distilled water, refer to paragraph 220-24.47).
   b. Methyl purple indicator (the contents of 1 methyl purple indicator capsule dissolved in 50 ml of distilled water, refer to paragraph 220-24.50).
   c. Distilled water.
3. Procedure
   a. Rinse the casserole and stirring rod with distilled water.
   b. Rinse a 100 ml graduated cylinder with distilled water and then with some of the standard.
   c. Measure exactly 50 ml of standard and pour it into the casserole.
   d. Add 2 to 3 drops of methyl purple indicator to the standard in the casserole. The standard will then turn green.

NOTE

Do not add phenolphthalein indicator as in the boiler water phosphate test.

e. Zero the buret. Add nitric acid 1 drop at a time, while stirring, until the standard turns purple. A gray color will appear just before the standard turns purple.

f. Read the buret. One ml equals one epm. Record the result in epm.

4. Acceptable limit: 5.4 to 6.6 epm. If result does not fall in this range, proceed as in paragraph 220-24.64.

220-26.36 STANDARDS TESTING

220-26.37

All standards are tested in the same manner as the applicable boiler water or feedwater sample, except for the alkalinity standard. The procedures are:

TEST PROCEDURES

Standard	Procedure
Feedwater Hardness	220-26.18
Boiler Water Chloride	220-26.31
Boiler Water Conductivity	220-26.30
Alkalinity	220-26.35

220-26.38

To interpret test results, refer to paragraphs 220-24.59 through 220-24.64.

SECTION 27.

WATER CHEMISTRY RECORDS AND DATA ANALYSIS

220-27.1 PERSONNEL RESPONSIBILITIES

220-27.2

The importance of the feedwater and boiler water chemistry logs and records must not be underestimated. Data collected and reflected in the logs and records must not be an end in itself, but rather a means to be utilized by the Engineer Officer and his assistants to measure the performance, stability, efficiency, and the state of material readiness of the engineering plant. The review of these logs and records must support the decision-making process involved in an effective water chemistry program.

220-27.3

The responsibilities of personnel regarding logs and records are as follows:

1. Oil Water King/Duty Oil Water King
   a. Maintains the Chelant Treatment Feedwater Chemistry Worksheet/Log, the Chelant Treatment Boiler Water Chemistry Worksheet/Log, and the Reserve/Makeup Feedwater Tests Log.
   b. Recommends treatment action based on log entries.
   c. Circles any result which is out of limits.
   d. Prepares the daily fuel and water report. (COMMANDING OFFICER DISCRETION)

e. Prepares the monthly Boiler Water/Feedwater Test and Treatment Chemical Inventory Log. (COMMANDING OFFICER DISCRETION)

f. Prepares the monthly boiler data and collates the logs for a particular machinery plant into a monthly water treatment log package.

2. Leading Chief Petty Officer (LCPO)

   a. Supervises the maintenance of the records and reviews the records daily.

   b. Maintains the central file (and an adequate supply) of the logs and the report.

   c. Analyzes logs for trends,

3. Engineer Officer of the Watch (EOOW)/Engineering Duty Officer (EDO)

   a. Ensures that the Oil/Water King or Duty Oil/ Water King is notified in advance of any boiler operation change which will affect water chemistry.

   b. Shall be cognizant of the logs and be aware of the data reflected in them to assist him in concurring or disagreeing with a recommended treatment action.

   c. Initials all boiler water test results.

   d. Initials any feedwater test result which is out of limits.

4. Main Propulsion Assistant (MPA)

   a. Indoctrinates the EOOW in the interpretation of the logs so that any treatment recommendations can be properly evaluated.

5. Engineer Officer

   a. Is responsible for the decisions regarding all boiler water/feedwater chemistry actions.

220-27.4 RECORD MAINTENANCE

220-27.5

There are 6 forms available for recording the necessary data used to assist in maintaining proper water conditions in a steam propulsion plant. The records are:

1. Cover Sheet and Monthly Boiler Data, NAVSEA 9255/6 (6-94).
2. Boiler Water/Feedwater Test and Treatment Chemical Inventory Log, NAVSEA 9255/16 (6-94),(COMMANDING OFFICER DISCRETION).
3. Chelant Treatment Feedwater Chemistry Worksheet/Log, NAVSEA 9255/14 (6-94).
4. Reserve/Makeup Feedwater Tests Log, NAVSEA 9255/10 (6-94).
5. Chelant Treatment Boiler Water Chemistry Worksheet/Log, NAVSEA 9255/15 (6-94).
6. Fuel and Water Report, NAVSEA 9255/9 (6-94),(COMMANDING OFFICER DISCRETION).

220-27.6

A complete Machinery Plant Water Treatment Log Package for a month shall be compiled in this order for each machinery space. This package shall be comprised of:

1. The cover sheet and monthly boiler data.

2. The daily chelant treatment feedwater chemistry worksheet/logs for the month.

3. The daily chelant treatment boiler water chemistry worksheet/log for each boiler in the space for the month.

220-27.7

The Machinery Plant Water Treatment Log Package is retained for 2 years.

220-27.8

The daily log for the reserve/makeup feedwater tests is retained for 3 months. The optional daily fuel and water report and chemical inventory log are retained for 1 month. A sample of each of these forms is shown in Figure 220-27-1 at the end of the section.

220-27.9 COVER SHEET AND MONTHLY BOILER DATA.

This form (Figure 220-27-1, sheets 1 and 2) shall be completed as follows:

1. On the front side (sheet 1) enter:
   a. Machinery plant number.
   b. Ship name and hull number.
   c. Month and year.
   d. Total number of pages for the complete Machinery Plant Water Treatment Package at the end of the month. (Number each page in the package beginning each month with the cover sheet being number 1.)
2. On the reverse side (sheet 2) enter the appropriate data for each boiler associated with this machinery plant system. Data which has changed during the month should be updated. Total steaming hours are lifetime totals for the boiler and are never zeroed. Hours of moderate and serious contamination are monthly total. Data which has not changed from the previous month should be brought forward. Additional blocks are provided in the areas of Dates of Important Evolutions and Governor Settings to record data which may be generated by repeated testing of equipment during a given month.

220-27.10 BOILER WATER/FEEDWATER TEST AND TREATMENT CHEMICAL INVENTORY LOG.

This log (Figure 220-27-1, sheets 3 and 4) provides a record of monthly inventory of test and treatment chemicals. It is required to ensure maintenance of sufficient onboard supplies of in date material. This log is optional at the Commanding Officer's Discretion.

a. The quantity onboard with less than six months shelf life remaining. Do not record expired material.

b. The quantity onboard with six or more months shelf life remaining.

c. The minimum onboard stock required for a six month deployment (see paragraph 220-28.22).

d. Determine if the quantities onboard are sufficient by recording yes or no in the sufficient onboard stock column. If the quantity onboard is not sufficient, the ″no″ entry shall be circled in the log.

220-27.11 Chelant treatment feedwater chemistry worksheet/log.

The daily log (Figure 220-27-1, sheets 5 and 6) consists of the following sections:

1. Chemical Tests and Salinity/Conductivity Indicator Comparison
2. Feedwater Tests.
3. Feedwater Treatment.
4. Requirements/Limits.
5. Remarks.

220-27.12

Initiate a daily log by inserting the system number, ship name and hull number, and date. When there is more than one condensate/feedwater system, a separate log is required for each system.

220-27.13 Chemical Tests and Salinity/Conductivity Indicator Comparison Section.

This section (Figure 220-27-1, sheet 5) shall be maintained for all feedwater components that are monitored by salinity or conductivity indicators as follows:

1. Enter the location of any salinity/conductivity indicators.
2. Enter the time of simultaneous chemical sampling and reading of the salinity/conductivity indicator. For makeup feed enter the time of the salinity/conductivity indicator reading.
3. Enter the buret reading and the calculated chloride chemical test result.
4. Enter the salinity/conductivity indicator result. Express results in epm by dividing µmho/cm result by 145 to convert to epm. Results obtained during salinity/conductivity indicator comparison tests are analytical results. Any result which is out of limits is circled. Refer to paragraph 220-27.16.
5. Check satisfactory or unsatisfactory based on the directions in paragraph 220-22.6.
6. When necessary, insert the buret reading and the calculated hardness chemical test result. Refer to paragraph 220-22.6.
7. The Oil King enters his initials and notifies the EOOW/EDO of test results.

220-27.14 Feedwater Tests Section.

This section is used whenever a salinity or conductivity indicator is faulty and it becomes necessary to sample and chemically test every four hours. It is also used to record the data obtained when samples are tested in order to locate contamination sources. In addition, the daily distillate air ejector drains result will be logged in this section, as well as daily chloride and hardness chemical tests performed on LP drains when steaming inport. This section (Figure 220-27-1, sheet 5) shall be maintained by all Feedwater system components, except reserve/makeup feed, as follows:

1. Enter the time of completion of sampling and reading of the salinity/conductivity indicator.
2. Enter the location from which the sample was drawn.
3. Enter the salinity/conductivity indicator result. Express results in epm by dividing µmho/cm result by 145 to convert to epm. The indicator reading columns are used to enter readings that are out of limits. Therefore, the Oil King must be notified whenever an alarm condition exists.
4. Enter the buret reading and the calculated chloride test result.

5. Enter the buret reading and the calculated hardness chemical test result. Hardness is not determined routinely for feedwater components (except for reserve feedwater, which is recorded on the reserve makeup feedwater log). Refer to requirements/limits section for applicable results.

6. The Oil King enters his initials and notifies the EOOW/EDO of test results.

220-27.15 Feedwater Treatment Section.

The feedwater treatment section shall be maintained as follows:

1. Enter the time of completion of sampling, the time the continuous treatment system is placed on-line or secured, and the time of completion of preparation of the continuous treatment tank.

2. Enter the appropriate code as given on the back of the log sheet.

3. Enter the following as required:
   a. Dissolved oxygen test result.
   b. Hydrazine test result.
   c. Ounces of EDTA, the ounces of disodium or trisodium phosphate, and the gallons of hydrazine used to prepare the treatment tank.
   d. Continuous treatment tank solution level.
   e. Mixing tank nitrogen pressure.

220-27.16 Remarks Section.

The remarks section (Figure 220-27-1, sheet 6) shall contain an explanation of each test result which is out of limits, a brief summary of feed system repairs accomplished, the status of repairs or replacement for any malfunctioning salinity or conductivity indicator, and a description of any unusual condition. All remarks are accompanied by the time as appropriate. Additional pages for remarks may be inserted as necessary.

220-27.17

The Chelant Feedwater Chemistry Worksheet/Log need not be prepared on a daily basis if a plant is in a cold iron status and no testing is required. When no testing is required, enter the inclusive dates on the front of one log and give the reason in the remarks section.

220-27.18

For every day that there is a log, the LCPO shall review and initial the log.

220-27.19 RESERVE/MAKEUP FEEDWATER TESTS LOG.

This daily log (Figure 220-27-1, sheets 7 and 8) consists of the following sections:

1. Reserve/Makeup Feedwater Tests.

2. Shore Source Feedwater Chemical Test Data Section.

3. Remarks.

220-27.20

Initiate the daily log by inserting the ship name and hull number, and the date.

220-27.21 Reserve/Makeup Feedwater Section (Without Demineralizers).

This section (Figure 220-27-1, sheet 7) for systems without demineralizers shall be maintained as follows:

1. For a reserve feedwater tank which requires a daily chemical test, enter the tank number, time of sampling, appropriate test code, the ml of mercuric nitrate used and the calculated chloride test result, the ml of EDTA used and the calculated hardness test result.
2. When the makeup feedwater salinity or conductivity indicator is satisfactory and another reserve feedwater tank is placed on makeup feed, enter the tank number, the time the tank is placed on makeup, and appropriate test code. Enter the indicator reading in the applicable salinity/conductivity indicator column. Leave the chloride column blank.
3. When the salinity or conductivity indicator is faulty and the reserve feedwater tank is sampled within 30 minutes prior to being placed on makeup, enter the tank number, the time of sampling, appropriate test code, the ml of mercuric nitrate used, and the calculated chloride test result.

220-27.22 Reserve/Makeup Feedwater Section (Without Demineralizers).

This section (Figure 220-27-1, sheet 7) for systems without demineralizers shall be maintained as follows:

1. For a reserve feedwater tank which requires a daily chemical test, enter the tank number, time of sampling, appropriate test code, the ml of mercuric nitrate used and the calculated chloride test result, the ml of EDTA used, and the calculated hardness test result.
2. When a reserve feedwater tank is placed on makeup feed, enter the tank number, the time the tank is placed on makeup, the inlet conductivity reading, and the outlet conductivity reading.
3. When the demineralizer system is not in operation, or is being bypassed, note this fact in the remarks section. The requirements in paragraph 220-27.21 shall then apply.

220-27.23 Shore Source Feedwater Chemical Test Data Section.

This section (Figure 220-27-1, sheet 8) shall be maintained for shore source feedwater as follows:

1. Record the pH, hardness, conductivity and silica results provided by the activity supplying the shore source feedwater.
2. Record the pH, hardness and silica of shore source feedwater as determined by ship’s force. If conductivity is too low to measure, record < 40 µmho/cm.
3. If multiple testing is required, insert the first set of results in the test data section. Insert follow-on results in the remarks section.
4. Identify the activity providing the shore feedwater.

220-27.24 REMARKS SECTION.

This section (Figure 220-27-1, sheet 8) shall contain an explanation of each test result which is out of limits, the status of repairs for any demineralizer system which is not in operation, and a description of any unusual condition. All remarks are accompanied by the date and time as appropriate. Additional pages for remarks shall be inserted as necessary.

220-27.25

The Reserve/Makeup Feedwater Tests Log need not be prepared on a daily basis if no testing is required. When no testing is required, enter the inclusive dates on the front of one log and give the reason in the remarks section.

220-27.26

For every day that there is a log, the LCPO shall review and initial the log.

220-27.27 CHELANT TREATMENT BOILER WATER CHEMISTRY WORKSHEET/LOG.

The daily log (Figure 220-27-1, sheets 9, and 10) consists of the following sections:

1. Chemical Test Results.
2. Batch Chemical Treatment.
3. Blowdown.
4. Steaming Hour Data.
5. Remarks.

220-27.28

Initiate the daily log for each boiler by inserting the boiler number, the ship name and hull number, and the date.

220-27.29 Chemical Test Results Section.

This section (Figure 220-27-1, sheet 9) shall be maintained as follows:

1. Enter the time on a 24 hour clock basis for the following:
   a. Completion of boiler water sampling.
   b. Reading of the continuous conductivity monitor.
   c. Commencement of layup conditions.
   d. Securing of layup conditions.
   e. Light-off.
   f. On-line.
   g. Securing.
   h. Completion of dumping.
   i. Completion of freshly filling.

j. Completion of batch chemical additions.
k. Completion of blowdowns.
l. Completion of any tests including hydrostatic tests.
m. Initiation of continuous blowdown.
n. Securing of continuous blowdown.
o. Other items of interest.

2. Enter the appropriate code as given on the back of the log. If a specific code is not provided, enter OTH and write out what took place in the remarks section. If the boiler is not steaming, a 0001 entry should be made each day with the appropriate layup code. One sheet may be used to cover a number of days in a single month if a boiler is under layup, but a date should be added to the time (day of month followed by time), for example, 050001 STM.

3. For each boiler water sample, record:
   a. Continuous conductivity monitor reading.
   b. Sample temperature and the conductivity (lab).
   c. The ml of nitric acid needed to change phenolphthalein from pink to colorless and the calculated alkalinity test result.
   d. The ml of nitric acid needed to change methyl purple from green to purple, and the calculated phosphate test result.
   e. The ml of mercuric nitrate used and the calculated chloride test result.
   f. The percent boiler load by the following formula:
   The percent boiler load for M type boilers is calculated for boiler water treatment considerations by using

$$\%\ \text{BOILER LOAD} = 100 \times \frac{\text{BFR} \times \text{BIS}}{\text{FPFR}}$$

where: BFR = Burner firing rate in lbs/hr obtained from sprayer plate capacity curve knowing the fuel oil header pressure

BIS = Number of burners in service

FPFR = Boiler full power firing rate in lbs/hr or burner full power firing rate in lbs/hr multiplied by the maximum number of burners per boiler

   the above formula for the saturated side only. Each ship should prepare a table for percent boiler load for various fuel oil header pressures and burner alignments. Percent boiler load shall be rounded to the nearest whole number.

4. The Oil King enters his initials and the reviewing EOOW/EDO enters his initials upon completion of the tests.

220-27.30 Batch Chemical Treatment Section.

This section (Figure 220-27-1, sheet 9) shall be maintained as follows:

1. Enter the amount of trisodium phosphate, disodium phosphate, or caustic soda required.

2. Enter the time of completion of the 10-minute flush when injecting treatment chemicals.

3. Enter the total amounts of all chemicals used for the day on the last log for the day.

220-27.31 Blowdown Section.

This section (Figure 220-27-1, sheet 9) shall be maintained as follows:

1. Enter the times of initiation and completion of a scum, surface, or bottom blowdown operation. If a blowdown spans two dates, record time on the date of completion.
2. Enter the appropriate code, as given on the back of the log, for the type of blowdown.
3. For surface blowdown (not scum blowdown), enter the conductivity before blowdown, the conductivity after blowdown, and the calculated percent blowdown. Round to the nearest whole number (i.e. 10.4% rounds to 10%, 10.5% rounds to 11%).
4. Enter the total percent of surface blowdown on the last log for the day.

220-27.32 Steaming Hours Data Section.

This section (Figure 220-27-1, sheet 10) shall be completed by entering into the **prior hours steamed this month** blocks the **steaming hours** and **steaming hours under moderate** and **serious contamination** from the **hours steamed this month** blocks of the previous day's log. For the first day of the month, enter zeros into the **prior hours steamed this month** blocks. Enter into the **hours steamed today** blocks the current day's **steaming hours** and **steaming hours under moderate** and **serious contamination** . **Steaming hours** are recorded to the nearest 0.1 hours from light-off to securing. **Steaming hours** under contamination start from the sample time when the contamination was detected to the sample time when the boiler water conditions are back within limits or the boiler is secured. Add the **prior hours steamed this month** to the **hours steamed today** to obtain the **hours steamed this month** . Enter the **hours since last waterside inspection, fireside inspection, surface blowdown** and **bottom blowdown** . If more than one log is used for the boiler in any one day, then enter the data on the last log for the day.

220-27.33 Remarks Section.

The remarks section (Figure 220-27-1, sheet 10) shall describe significant events of the day related to that boiler. Additional pages for remarks shall be inserted as necessary. All remarks are accompanied by the time as appropriate. If a doubt exists as to whether or not an entry should be made in the remarks section, enter it. The following types of events shall be recorded:

1. The setting of boiler safety valves.
2. Hydrostatic tests, including purpose and pressure, and the signature of the witnessing individual.
3. A brief summary of boiler repairs accomplished.
4. Boiler inspection.
5. Explanation of each test result which is out of limits.
6. Description of unusual conditions.
7. The results of tests of boiler water/feedwater chemicals against standards, except the quarterly tests, are entered on the log for the 1 or 1A boiler. (The quarterly standard test results are entered on the monthly boiler data log for the number 1 plant.)
8. Theoretical conductivity for a steaming boiler once daily.

220-27.34

The Chelant Treatment Boiler Water Chemistry Worksheet/Log need not be prepared on a daily basis when the boiler is idle. When no testing is required and no change in boiler condition is occurring, enter the inclusive dates on the front of one log and enter the type of layup applied in the code column, and describe significant events occurring during the idle period.

220-27.35

For every day that there is a log the LCPO shall review and initial the log.

220-27.36 FUEL AND WATER REPORT (OPTIONAL AT COMMANDING OFFICER'S DISCRETION).

A daily report of the fuel and water status is prepared to reflect the conditions at 2400 hours. This report also provides information on feedwater and boiler water conditions. The daily Fuel and Water Report (Figure 220-27-1, sheets 11 and 12) is prepared as follows:

1. On the front side (Figure 220-27-1, sheet 11):
   a. Enter the date.
   b. Enter the ship name and hull number.
   c. From the previous day's report, and the usage data as of 2400, determine the amount of boiler/gas turbine (GT) fuel and diesel (JP-5) fuel onboard. Calculate the onboard percentage based on 95% fill capacity of the tank and enter the appropriate data.
   d. From the previous day's report, and the usage data as of 2400, determine the amount of lube oil onboard. The amount of lube oil should reflect that which is in all storage and settling tanks. Lube oil located in main engine and auxiliary sumps should be recorded as expended as of the time the lube oil is placed in the particular sump. Calculate the onboard percentage and enter the appropriate data. If desired, there is adequate space at the bottom of the form to indicate the amount of oil in the main engine sumps.
   e. From the previous day's report, the amount distilled, and the usage data as of 2400, determine the amount of potable water and reserve feedwater onboard. Calculate the onboard percentage of capacity and enter the appropriate data.

NOTE

The total amount distilled should be equal to the total evaporator output during the day.

   f. The amount of potable water expended and the number of personnel onboard are used to determine the number of gallons used per person. These are entered. Each class ship has a standard usage which is based on a normal complement. This is entered.
   g. Enter feedwater consumption in gallons per hour.
   h. Remarks concerning unusual conditions are entered.
2. On the reverse side (Figure 220-27-1, sheet 12):
   a. Enter the boiler designation.
   b. Enter the fireside hours since last inspection for each boiler.
   c. Enter the waterside hours since last inspection for each boiler.
   d. Enter the boiler water chemical test results for the last sample for each boiler as of 2400 hrs. Enter the

minimum and maximum values for the chemical test results obtained for each boiler for the day of record. Enter the hours steamed under moderate and serious contamination. A boiler out of commission is so indicated. This data is determined from the Boiler Water Chemistry Worksheet/Log.

e. Enter the layup code for the type of layup applied to each idle boiler and the days under layup.

f. Enter the number of steaming hours since last bottom blowdown.

g. Enter the range of results obtained for feedwater in each system for the previous day ending at 2400.

h. The Oil King initials the report. The MPA and Engineer Officer review and sign the back of the report.

220-27.37 DATA EVALUATION

220-27.38

The logs serve to record the past history and present condition of the steam plant water chemistry. The evaluation of the data of a particular log will enable the Engineer Officer and his assistants to provide proper treatment and other corrective action in order to maintain the water chemistry of the steam plants within the proper ranges.

220-27.39 FUEL AND WATER REPORT.

The following information may be drawn from an analysis of the Fuel and Water Report data:

1. Waterside and fireside hours serve as an aid in scheduling required maintenance and steaming of specific boilers.
2. Boiler water and feedwater data provide an overview of current water chemistry conditions.
3. Fuel and feedwater consumption is related to plant efficiency. These also serve as a guide for computing fuel and feedwater requirements.
4. Potable water and reserve feedwater consumption are two factors which must be compared to distilling plant output and capacity. Any unusual use in either potable water or reserve feedwater usage should be investigated.

220-27.40 CHELANT TREATMENT FEEDWATER CHEMISTRY WORKSHEET/LOG.

Analysis of the Feedwater Chemistry Worksheet/Log may lead to the following actions:

1. **Chemical Tests and Salinity/Conductivity Indicator Comparison.** This section shows the reliability of the salinity or conductivity indicating systems. Salinity or conductivity indicators detect an increase in contaminant level rapidly. Any salinity indicators or conductivity indicators that test unsatisfactorily must be repaired as soon as possible.
2. **Feedwater Tests.** The chloride result indicates the general level of seawater contamination. Increasing chloride levels or results above 0.02 epm indicate that seawater contamination is entering the feedwater system. The source of contamination shall be determined and corrected. A hardness result above 0.02 epm with a normal chloride result indicates shore water contamination. When hardness is present in deaerated feedwater, the service steam system must be checked for hardness. A high salinity/conductivity indicator reading with a low chemical chloride test result is also an indicator of shore water contamination. If shore water contamination is suspected, test the affected component for hardness. The salinity/conductivity systems will assist in locating both seawater and shore water contamination. Contamination of the feedwater will have an effect on boiler water chemistry and will therefore be reflected in the boiler water log.

3. **Deaerated Feedwater Test.** The dissolved oxygen test indicates the effectiveness of the DFT. Any reading above 15 ppb must be investigated. Frequent high or low hydrazine requires that continuous injection system be inspected for proper operation.

220-27.41 RESERVE/MAKEUP FEEDWATER TESTS LOG.

The quality of the reserve feedwater available for use or the actual quality of the makeup being used is reflected in this log. The makeup feed salinity/conductivity indicator reading or the inlet conductivity reading of the reserve feed demineralizer represents the overall quality of reserve feedwater. Increasing or high values of either of these two readings indicate either poor quality reserve or distillate. A fast rise of the outlet conductivity is a warning that the resin bed is about to be exhausted. If consistent low readings on the outlet conductivity are not obtained shortly after placing a fresh resin bed in the demineralizer, the resin may be of poor quality or the resin bed may not have been prepared properly. An increase in the daily chloride and hardness value of an unused reserve feedwater tank indicates that tank integrity is questionable. The results for shore feedwater or shore steam indicate the quality of the feedwater or steam which will be used.

220-27.42 BOILER WATER CHEMISTRY WORKSHEET/LOG.

The data from the Boiler Water Chemistry Worksheet/Log assist in interpreting the causes of changes in boiler water chemistry and allow engineering personnel an opportunity to anticipate the effects that changes in boiler operation will have on boiler water control. Some examples are:

1. If conductivity and chloride increase, while alkalinity and phosphate decrease, seawater contamination is probable.
2. If alkalinity and conductivity increase slightly, while phosphate decreases and chloride remains relatively constant, shore water contamination is probable.
3. When chemical hideout occurs, observation of the changes in alkalinity and phosphate under varying load conditions will allow engineering personnel to anticipate treatment action which will be required when similar circumstances again arise.
4. Load variation may also cause boiler water parameters to vary slightly under normal conditions. These can be anticipated.
5. A decrease in all boiler water chemistry parameters, without excessive continuous blowdown, indicates carryover or boiler leakage.
6. A slow increase in chloride above normal indicates a small seawater leak whose source should be located.
7. Inexplicable changes in one parameter, and no other, indicate a sampling or testing problem.
8. Increase in the frequency of surface blowdown indicates the development of a contaminating condition.
9. If boiler water control problems routinely develop at a certain time of day, contamination sources are narrowed to equipment which operate intermittently (for example, in the laundry, sculleries).

220-27.43 ROUGH AND SMOOTH RECORDS

220-27.44

Every time that data is transferred from one sheet of paper to another, the likelihood of error exists. Any practice of increasing the number of times data is transferred, by maintaining rough working logs and then preparing smooth logs for file, is prohibited. The individual who is recording data should record data on the appropriate log only. The logs may be prepared either in ink or pencil at the option of the person who is developing the data. No erasure is permitted on the feedwater chemistry worksheet/log or the boiler water chemistry worksheet/log. If an error is made, line through and initial the error, then enter the correct number.

220-27.45

The Oil King who is performing the analyses shall maintain the feedwater chemistry worksheet/log and the boiler water chemistry worksheet/log. If for convenience a ship wishes to record these data in an area such as main/central control, this is permissible; however, the boiler water and feedwater chemistry worksheet/logs submitted in the log package shall be those which were maintained in the laboratory by the Oil King.

220-27.46 DISPOSAL/RETENTION REQUIREMENTS FOR WATER CHEMISTRY RECORDS

220-27.47

The monthly water treatment log package including the cover sheet and monthly boiler data, the feedwater chemistry worksheet/log, the boiler water chemistry worksheet/log shall be retained onboard for 2 years, at which time they may be discarded. The reserve/makeup feedwater tests log shall be retained for 3 months and may then be discarded. The fuel and water report shall be retained for 1 month and may then be discarded.

220-27.48 OPERATION/SAFETY PLACARDS

220-27.49

Operation and safety placards for treatment and sampling procedures shall be posted in appropriate places as follows:

1. **Boiler water sampling.** Each boiler water sample cooler area.
2. **Desuperheater sampling.** Each desuperheater sample cooler area.
3. **Dissolved oxygen sampling.** Each DFT sample cooler area.
4. **Feedwater sampling.** Each DFT sample cooler area.
5. **Boiler chemical injection system.** Each injection tank area.
6. **Makeup feed demineralizer operation and maintenance.** Each demineralizer tank area.
7. **Preparation of Continuous Treatment Solution.** Each continuous treatment system control panel.
8. **Injection of Continuous Treatment Solution.** Each continuous treatment system control panel.
9. **Preparation of Layup Treatment Solution.** Each continuous treatment system control panel.
10. **Injection of Layup Treatment Solution.** Each continuous treatment system control panel.
11. **Feedwater Hydrazine Test.** Each DFT sample cooler area.
12. **Boiler Water Sampling/Continuous Blowdown.** Each boiler water sample cooler area.
13. **DFT Warning, ″FEEDWATER TREATED WITH HYDRAZINE. DO NOT DRINK″.** Each DFT sample cooler area.

220-27.50

Placards are normally supplied by the installing activity at the time of equipment installation. If placards are missing, prepare them locally. The necessary technical information for placards is contained in the applicable sections of this technical manual. For demineralizer operation and maintenance, refer to NAVSEA Technical Manual S9255-AQ-MMO-010.

WATER TREATMENT LOG

MACHINERY PLANT NO. 1

USS FRIGATE (FF-1100)

MONTH AUGUST, YEAR 1994

CONSISTING OF PAGES 1 THROUGH 76

REVIEWED Lt M.H. Sebring, USN 3 Sept 1994
ENGINEER OFFICER DATE

EXAMINED Cdr J. R. Palmer, USN 4 Sep 94
COMMANDING OFFICER DATE

NOTE: THIS RECORD WILL BE RETAINED ON BOARD FOR 2 YEARS AND DISPOSED OF IN ACCORDANCE WITH SECNAVINST 5212.B.SUP-1, PARA. 9510(1). TRANSCRIPT(S) WILL BE FURNISHED TO NAVSEASYSCOM WHEN REQUIRED.

NAVSEA 9255/6 (6-94)(FRONT) NSN 0116-LF-018-2300

Figure 220-27-1 Treatment Log (Sheet 1 of 12)

MONTHLY BOILER DATA

BOILER NO.	1A	1B	
STEAMING HOUR DATA			
TOTAL LAST MONTH	38,690.2	36,144.1	
HOURS THIS MONTH	175.3	101.2	
TOTAL STEAMING HOURS	38,865.5	36,245.3	
HOURS RUN DRY			
CONTAMINATION			
STM. HRS. MODERATE	22	16	
STM. HRS. SERIOUS	2	5	
INSPECTIONS			
SGPI			
DATE LAST INSPECTED	17JUL94	18JUL94	
INSPECTED BY	IMA	IMA	
STM. HRS. SINCE INSP.	2167.5	2218.0	
CHENG			
WATERSIDES			
DATE LAST INSPECTED	3FEB94	7FEB94	
INSPECTED BY	SEBRING	SEBRING	
STM. HRS. SINCE INSP.	2714.0	2872.5	
FIRESIDES			
DATE LAST INSPECTED	3FEB94	7FEB94	
INSPECTED BY	SEBRING	SEBRING	
STM. HRS. SINCE INSP.	2714.0	2872.5	
CLEANINGS			
WATER JET, WIREBRUSH OR EDTA WATERSIDE CLEANING			
DATE LAST CLEANED	6JUN93	7JUN93	
TYPE OF CLEANING	EDTA	EDTA	
STM. HRS. SINCE CLN.	3875.5	3947.3	
HYDROCHLORIC/SULFAMIC ACID WATERSIDE CLEANING			
DATE LAST CLEANED	11MAY87	16MAY87	
STM. HRS. SINCE CLN.	52,017.9	50,746.8	
FIRESIDE CLEANING			
DATE LAST CLEANED	6JUN93	7JUN93	
STM. HRS. SINCE CLN.	3875.5	3947.3	
CHEMICAL AND BLOWDOWN DATA			
TOTAL oz/g TSP	92	79	
TOTAL oz/g DSP	93	85	
TOTAL OUNCES C.S.	0	0	
NO. OF SURFACE BLOWS	4	3	
NO. OF BOTTOM BLOWS	2	1	

BOILER SAFETY VALVES SET	DATE	PRESSURE LIFT	PRESSURE RESEAT
BOILER NO. 1A			
PILOT	11MAR94	1370	1295
SUPERHEATER	11MAR94	1385	1315
#1 DRUM	11MAR94	1390	1330
#2 DRUM	11MAR94	1400	1350
#3 DRUM			
#4 DRUM			
BOILER NO. 1B			
PILOT	12MAR94	1360	1305
SUPERHEATER	12MAR94	1390	1320
#1 DRUM	12MAR94	1395	1320
#2 DRUM	12MAR94	1405	1350
#3 DRUM			
#4 DRUM			
BOILER NO.			
PILOT			
SUPERHEATER			
#1 DRUM			
#2 DRUM			
#3 DRUM			
#4 DRUM			

WATER CHEMISTRY STANDARDS RUN		
TEST	DATE	RESULT
CONDUCTIVITY	6JUL94	1400 µMHO/CM
CHLORIDE	6JUL94	1.96 epm
ALKALINITY	6JUL94	6.0 epm
HARDNESS	6JUL94	0.18 epm

DATES OF IMPORTANT EVOLUTIONS			
BOILER NO.	1A	1B	
LAST 150% HYDRO	8JUN91	9JUN91	
LAST 135% HYDRO	11MAY92	12MAY92	
LAST 125% HYDRO	20FEB93	21FEB93	
LAST TUBE NDE			
SOOT BLOWER NDE	1FEB94	1FEB94	
BOTTOM BLOWDOWN PIPING NDE	3MAY94	3MAY94	
AIR CASING TEST	5JAN94	5JAN94	
SATISFACTORY BOILER FLEXIBILITY TEST	4DEC93	4DEC93	

GOVERNOR SETTINGS										
NUMBER		1A1	1A2	1B1	1B2					
FORCED DRAFT BLOWERS	DATE / SETTING	7/20/94 5770	7/20/94 5790	7/21/94 5775	7/21/94 5780					
NUMBER										
FUEL OIL SERVICE PUMPS	DATE / SETTING									
NUMBER		1A	1B	1C						
MAIN FEED PUMPS	DATE / SETTING	7/21/94 7750	7/21/94 7720	7/21/94 7700						
NUMBER										
MAIN FEED BOOSTER PUMPS	DATE / SETTING									

NAVSEA 9255/6 (6-94)(BACK)　　NSN 0116-LF-018-2300

Figure 220-27-1 Treatment Log (Sheet 2of 12)

BOILER WATER/FEEDWATER TEST AND TREATMENT CHEMICAL INVENTORY LOG

SHIP USS FRIGATE (FF-1100) DATE JUNE 1994 PAGE 3

ITEM	NSN	QTY WITH LESS THAN 6 MONTHS SHELF LIFE REMAINING	QTY WITH 6 MONTHS OR MORE SHELF LIFE REMAINING	QTY REQUIRED FOR 6 MONTH DEPLOYMENT	SUFFICIENT ONBOARD STOCK? YES/NO
STANDARDS					
CHLORIDE (2.0 epm)	9G 6810-01-129-3762	5	20	12	YES
CONDUCTIVITY (1,400 μmho/cm)	9G 6810-00-945-7682	—	14	12	YES
HARDNESS (0.2 epm)	9G 6810-01-125-5234	—	15	8	YES
METHYL PURPLE ALKALINITY (6.0 epm)	9G 6810-01-250-8231	2 (JUL 94)	2	4	NO
pH 7.00 ± 0.05 at 25°C	9G 6810-01-239-7562	1 (OCT 94)	3	4	YES
pH 10.00 ± 0.05 at 25°C	9G 6810-01-239-7563	—	8	4	YES
TREATMENT CHEMICALS					
CAUSTIC SODA (LYE, SODIUM HYDROXIDE)	9G 6810-00-270-8177	—	6	4	YES
DISODIUM PHOSPHATE ANHYDROUS (SODIUM PHOSPHATE, DIBASIC, O-S-639)	9G 6810-00-584-4296	—	8	4	YES
HYDRAZINE, 7%	1H 6810-01-304-5373	—	—	—	—
ION EXCHANGE RESIN	1H 6810-01-029-4217	—	15	12	YES
MORPHOLINE, 40%	9G 6810-00-419-4296	—	3	4	NO
NITROGEN (CHELANT TREATMENT)	9G 6830-00-656-1596	—	—	—	—
SODIUM NITRITE	9G 6810-00-270-3254	—	35	30	YES
TRISODIUM EDTA, TRIHYDRATE	1H 6810-01-312-4076	—	—	—	—
TRISODIUM PHOSPHATE DODECAHYDRATE (SODIUM PHOSPHATE, TRIBASIC, DODECAHYDRATE, O-S-642, TYPE II)	9G 6810-01-082-5415	—	14	8	YES

NAVSEA 9255/16 (6-94)(FRONT) NSN 0116-LF-018-3100

Figure 220-27-1 Treatment Log (Sheet 3 of 12)

BOILER WATER/~~FEEDWATER~~ TEST AND TREATMENT CHEMICAL INVENTORY LOG

SHIP USS FRIGATE (FF-1100) DATE JUNE 1994 PAGE 4

ITEM	NSN	QTY WITH LESS THAN 6 MONTHS SHELF LIFE REMAINING	QTY WITH 6 MONTHS OR MORE SHELF LIFE REMAINING	QTY REQUIRED FOR 6 MONTH DEPLOYMENT	SUFFICIENT ONBOARD STOCK? YES/NO
STOCK CHEMICALS AMINO ACID REAGENT PILLOWS	9G 6810-01-169-1770	—	1	1	YES
AMPOULES, 0-40 ppb OXYGEN	9L 6630-01-068-5210	1	7	7	YES
AMPOULES, HYDRAZINE	1H 6810-01-312-4075	—	—	—	—
CHLORIDE INDICATOR CAPSULES	9G 6810-00-753-4807	1	1	1	YES
CITRIC ACID REAGENT PILLOWS	9G 6810-01-169-8568	1	1	1	YES
DIMETHYLGLYOXIME	9G 6810-01-082-5414	—	2	1	YES
HARDNESS BUFFER	9G 6850-01-380-4335	—	2	1	YES
HARDNESS INDICATOR	9G 6850-01-380-4338	—	1	1	YES
HARDNESS TITRATING SOLUTION	9G 6810-01-072-1978	—	1	1	YES
ISOPROPYL ALCOHOL (ISOPROPANOL, 2-PROPANOL)	9G 6810-00-227-0410	—	2	1	YES
MERCURIC NITRATE	9G 6810-00-281-4163	—	3	3	YES
METHYL PURPLE INDICATOR CAPSULES	9G 6810-00-142-9290	—	1	1	YES
NITRIC ACID	9G 6810-00-270-9978	—	3	1	YES
PHENOLPHTHALEIN INDICATOR	9G 6810-00-223-7612	—	2	1	YES
POTASSIUM CHLORIDE CRYSTALS	9L 6810-00-136-1004	—	4	4	YES
SILICA-1 REAGENT	9G 6810-01-169-1773	—	1	1	YES

LCPO INITIAL	LCPO DATE	MPA INITIAL	MPA DATE	REVIEWED: (ENGINEER OFFICER)	DATE
PB SF	3 June 94	AE 77	3 June 94	Lt M H Sebring	3 June 1994

NAVSEA 9255/16 (6-94)(BACK) NSN 0116-LF-018-3100

Figure 220-27-1 Treatment Log (Sheet 4 of 12)

CHELANT TREATMENT FEEDWATER CHEMISTRY WORKSHEET/LOG

SYSTEM 1 SHIP USS SHIP (AE-35) DATE 1 JUN 94 PAGE 5

CHEMICAL TESTS AND SALINITY/CONDUCTIVITY INDICATOR COMPARISON (REQUIRED DAILY) NOTE: μmho/145=epm

TIME	INDICATOR LOCATION	CHLORIDE ml MERCURIC NITRATEx0.1= epm CHLORIDE		INDICATOR READING		COM- PARISON	HARDNESS ml EDTAx0.2= epm HARDNESS		OIL KING INITIAL
		ml	epm	μmho/cm	epm	SAT/ UNSAT	ml	epm	
0835	DFT	.1	.01		.06	UNSAT	0	0	RE
0839	MUF 92-1	.3	.03		.04	SAT			RE
0840	DEM INLET	.3	.03	5.8	.04	SAT			RE
0848	FWDCT	.2	.02		.02	SAT			RE
0910	IA SSTG	.1	.01		.000	SAT			RE
0945	DIST #1	.4	.04		.05	SAT			RE
0950	IB SSTG	.1	.01		.02	SAT			RE
0952	SWITRDR#1	.2	.02		.02	SAT			RE

FEEDWATER TREATMENT

TIME	CODE	DISSOLVED OXYGEN LIMIT: 15 ppb	HYDRAZINE RANGE: 10–40 ppb	CONTINUOUS INJECTION TANK TANK PRESSURE 40 psi			
				EDTA (ounces)	TSP/DSP (ounces)	HYDRAZINE (gallons)	TANK LEVEL (gallons)
0438	PFB	12.5					
0545	PRP			30	15	1	30
0815	CTOL						
1030	AOL	2.5					
1700	AOL		20				

FEEDWATER TESTS

TIME	LOCATION	INDICATOR READING μmho/cm / epm	CHLORIDE ml MERCURIC NITRATEx0.1= epm CHLORIDE		HARDNESS ml EDTAx0.2= epm HARDNESS		OIL KING INITIAL
			ml	epm	ml	epm	
1015	A/E DRN	.05	.1	.01			RE
1035	LP DRN		.1	.01	.1	.02	RE
1300	IA SSTG	.000	.1	.01			NEW
1450	FWDCT	.08	.3	.03	.9	.18	NEW
1455	LP DRN		.4	.04	1.1	.22	NEW
1458	DFT	.06	.4	.04	.8	.16	NEW
1535	FWDCT	.02	.2	.02	.1	.02	NEW
1625	HOT WTR		.4	.04	1.8	.36	DMG
1630	IA SSTG	.02	.1	.01			DMG
1705	LP DRN	.02	.2	.02	0	0	DMG

NAVSEA 9255/14 (6-94)(FRONT) NSN 0116-LF-018-2800

Figure 220-27-1 Treatment Log (Sheet 5 of 12)

CHELANT TREATMENT FEEDWATER CHEMISTRY WORKSHEET/LOG

PAGE 6

TIME	REMARKS:
0835	DFT-Check indicator for malfunction, sample and test on-line boiler(s) every
	4 hours until indicator is back in service.
0910	1A SSTG-Check indicator for malfunction, sample and test 1A SSTG every 4 hours
	for chloride until indicator is back in service.
1300	1A SSTG-Indicator malfunctioning, continuing 4-hour samples.
1450	FWDCT-Sample and test on-line boiler(s), seek and isolate source of contamination.
1452	Secured FWDCT discharge valve.
1455	LP DRN-Sample and test on-line boiler(s), seek and isolate source of contamination, align
	low pressure drains overboard, secured alignment to FWDCT.
1458	DFT-Sample and test on-line boiler(s), contamination has been determined to be
	coming from the low pressure drains.
1514	Pumped FWDCT to bilge.
1540	Realigned FWDCT to the condensate system.
1625	Contamination identified from galley hot water, isolated heater from system.
1630	1A SSTG salinity cell removed, cleaned and placed back in service by the
	IC men, return to normal sampling frequency.
1715	Realigned low pressure drains to FWDCT.

LEGEND/TEST CODE

DISSOLVED OXYGEN TESTING		CHELANT TREATMENT	
PFB	PRIOR TO FEEDING THE BOILER	AOL	8 TO 10 HOURS AFTER ON LINE
AOL	WITHIN 2–3 HOURS AFTER BOILER ON LINE	RTE	WITHIN 24 HOURS
RTE	WITHIN 24 HOURS	PRP	PREPARED CONTINUOUS INJECTION TANK
		CTOL	CONTINUOUS TREATMENT ON–LINE
		CTS	CONTINUOUS TREATMENT SECURED

REQUIREMENTS/LIMITS (MAXIMUM)		CHLORIDE epm		CONDUC–TIVITY µmho/cm	HARDNESS epm
		SALINITY INDICATOR	CHEMICAL TEST		
DISTILLATE		0.065	0.07	10.0	–
MAKEUP	DEMINERALIZED	–	–	1.0	–
	NONDEMINERALIZED	0.10	0.10	15.0	0.10
CONDENSATE, DRAINS, DFT		0.02	0.02	3.0	0.02
DISTILLER AIR EJECTOR DRAINS		0.065	0.02	10.0	–

LCPO INITIAL	LCPO DATE	MPA INITIAL	MPA DATE	REVIEWED: (ENGINEER OFFICER)	DATE:
MMKMM	2 Jun 94	JCW	2 Jun 94	Lt J.T. Clark	2 June 1994

NAVSEA 9255/14 (6–94)(BACK) NSN 0116–LF–018–2800

Figure 220-27-1 Treatment Log (Sheet 6 of 12)

RESERVE/MAKEUP FEEDWATER TESTS LOG

(FILL IN APPLICABLE COLUMNS)

SHIP USS FRIGATE (FF-1100) DATE 9 JUN 94

TANK NO.	TIME	CODE	SALINITY INDICATOR, epm	CONDUCTIVITY INDICATOR, µmho/cm	CHLORIDE (LIMIT: 0.10 epm MAX)		HARDNESS (LIMIT: 0.10 epm MAX)		DEMINERALIZER CONDUCTIVITY		OIL KING INITIAL
			LIMIT: 0.10 epm	LIMIT: 15 µmho/cm	ml MERCURIC NITRATE	ml x 0.1= epm	ml EDTA	ml x 0.2= epm	INLET MAX 15 µmho/cm	OUTLET MAX 1.0 µmho/cm	
5-107-0	0815	DAY			0.4	0.04	0.1	0.02			JES
5-110-0	0930	DAY			0.2	0.02	0	0			JES
WITH	DEMINERALIZER										
3-92-1	0005	PPS			0.3	0.03					MHH
3-92-1	0035	AOS							4.0	0.15	MHH
3-92-2	0255	AOS							5.8	0.10	MHH
WITHOUT	DEMINERALIZER										
3-92-1	0005	PPS			0.3	0.03					MHH
3-92-1	0035	AOS	0.03	4.0							MHH
3-92-2	0255	AOS	0.04	5.8							MHH

LEGEND/TEST CODE			
DAY DAILY	AOS AFTER ON SUCTION	PPS PRIOR TO PLACING ON SUCTION	OTH OTHER

NAVSEA 9255/10 (6-94)(FRONT) NSN 0116-LF-018-8700

Figure 220-27-1 Treatment Log (Sheet 7 of 12)

RESERVE/MAKEUP FEEDWATER TESTS LOG

PAGE________

TIME	REMARKS:

SHORE SOURCE FEEDWATER CHEMICAL TEST DATA

CONSTITUENT OR PROPERTY	STEAM CONDENSATE SUPPLIER	STEAM CONDENSATE SHIP	PROCESSED FEEDWATER SUPPLIER	PROCESSED FEEDWATER SHIP
pH				
RANGE	8.0–9.5	> 5.4	NOT REQ.	5.4–8.2
HARDNESS				
epm LIMIT	0.10	0.10	NOT REQ.	0.10
CONDUCTIVITY				
µmho/cm LIMIT	25	< 40	2.5	< 40
SILICA				
ppm LIMIT	0.2	0.2	0.2	0.2
ACTIVITY				

INIT.	LCPO DATE	INIT.	MPA DATE
PLG	10 Jun 94	SEN	10 Jun 94

REVIEWED (ENGINEER OFFICER) Lt M. H. Sebring DATE 10 June 1994

NAVSEA 9255/10 (6-94)(BACK) NSN 0116-LF-018-8700

Figure 220-27-1 Treatment Log (Sheet 8 of 12)

CHELANT TREATMENT BOILER WATER CHEMISTRY WORKSHEET/LOG

BOILER NO. 1A SHIP USS SHIP (AE-35) DATE 1 JUN 94 PAGE 60

TIME	CODE	CONDUCTIVITY LIMIT: 800 µmho/cm			ALKALINITY RANGE: 0.100 – 1.000 epm		PHOSPHATE RANGE: 10 – 40 ppm		CHLORIDE LIMIT: 1.0 epm		BOILER LOAD PERCENT %	OIL KING INITIAL	EOOW/ EDO INITIAL
		CONTINUOUS MONITOR µmho/cm	TEMP (°C)	µmho/cm	ml PHENOL-PHTHALEIN	ml/4 = epm	ml METHYL PURPLE	mlx25 = ppm	ml MERCURIC NITRATE	mlx0.4 = epm			
0001	STM												
0450	OTH												
0530	PTL		25	70	.4	0.100	.4	10	.3	.12		[illegible]	[illegible]
0625	LOF												
0900	ONL												
0925	AOL	70	25	75	.4	0.100	.4	10	.3	.12	5	RE [illegible]	[illegible]
0927	CBOL												
0920	ADD												
1045	ACA/PTB	140	26	150	1.0	0.250	1.0	25	.4	.16	10	RE [illegible]	[illegible]
1130	S-1												
1500	OTH	320	24	300	2.5	0.625	.1	JTR 2.5	.9	.36	20	[illegible]	[illegible]
1535	ADD												
1538	OTH												
1600	ACA	360	25	360	2.6	0.650	1.1	27.5	1.0	.40	15	[illegible]	[illegible]

BATCH CHEMICAL TREATMENT			
TRISODIUM PHOSPHATE (ounces)	DISODIUM PHOSPHATE (ounces)	CAUSTIC SODA (ounces)	TIME INJECTED
13			0920
	8.5		1535
13	8.5	Ø	TOTAL OUNCES

BLOWDOWN					
TIME START	TIME FINISH	TYPE	CONDUCTIVITY BEFORE	CONDUCTIVITY AFTER	% BLOWDOWN
1129	1130	S-1			

TOTAL PERCENT SURFACE BLOWDOWN Ø

NAVSEA 9255/15 (6-94)(FRONT) NSN 0116-LF-018-2900

Figure 220-27-1 Treatment Log (Sheet 9 of 12)

CHELANT TREATMENT BOILER WATER CHEMISTRY WORKSHEET/LOG

PAGE 61

TIME	REMARKS:
0450	OTH- Established boiler lightoff level.
0825	AOL- Batch treat with TSP prior to scum blowdown. Daily theoretical
	conductivity 64.7 SAT.
1500	OTH - FWDCT hardness chemical test .18 EPM, serious shore water
	contamination, seek and isolate source of contamination, batch treat with
	DSP, 15-30 minute ACA sample.
1538	FWDCT isolated.
1601	CHENG directed boiler water sample be obtained at 1630 to ensure boiler
	contamination is under control.
1630	Sample by order of CHENG. Next sample due by 2030 due to DFT
	salinity indicator malfunctioning.

LEGEND/TEST CODE

PTL WITHIN 60 MIN. PRIOR TO LIGHTOFF
AOL WITHIN 30 MIN. AFTER ON LINE
RTE WITHIN 24 HOURS
ADD BATCH CHEMICAL ADDITION
ACA 60 TO 90 MIN. AFTER CHEMICAL ADDITION
PTB WITHIN 60 MIN. PRIOR TO BLOWDOWN
ABD 30 TO 45 MIN. AFTER BLOWDOWN
PTS WITHIN 90 MIN. PRIOR TO SECURING
FFT FRESHLY FILLED AND TREATED
LOF LIGHTOFF
ONL ON LINE
SEC SECURED
D DUMPED
OTH OTHER
CBOL CONTINUOUS BLOWDOWN ON-LINE
CBS CONTINUOUS BLOWDOWN SECURED

BOILER LAYUP

DRY LAYUP
DES DESICCANT
HTD HEATED AIR

WET LAYUP
STM STEAM (SHIP)
STS STEAM (SHORE)
NIT NITROGEN
HYD HYDRAZINE

BLOWDOWNS
S SURFACE
S-1 SCUM
B BOTTOM

	STEAMING HOURS	STEAMING HOURS UNDER CONTAMINATION	
		MODERATE	SERIOUS
PRIOR HOURS STEAMED THIS MONTH	0	0	0
HOURS STEAMED TODAY	17.6	0	1.0
HOURS STEAMED THIS MONTH	17.6	0	1.0
HOURS SINCE LAST WATERSIDE INSPECTION	2,465.1		
HOURS SINCE LAST FIRESIDE INSPECTION	552.3		
HOURS SINCE LAST SURFACE BLOWDOWN	12.5		
HOURS SINCE LAST BOTTOM BLOWDOWN	17.6		

LCPO INITIAL	LCPO DATE	MPA INITIAL	MPA DATE	REVIEWED: (ENGINEER OFFICER)	DATE
MWM	2 June 94	JCW	2 June 94	Lt J T Clark	2 June 1994

NAVSEA 9255/15 (6-94)(BACK) NSN 0116-LF-018-2900

Figure 220-27-1 Treatment Log (Sheet 10 of 12)

FUEL AND WATER REPORT

DATE 13 JUN 94

TO: COMMANDING OFFICER, USS FRIGATE (FF-1100)

	FUEL (gallons)		LUBE OIL STORAGE TANKS (gallons)		WATER (gallons)	
	BOILER/GT FUEL	DIESEL FUEL/ JP-5	2190	9250/23699	POTABLE	RESERVE FEED
ON HAND LAST REPORT	224,000	15,200	1,500	1,700	9,050	9,080
RECEIVED (+)	0	0	0	0	0	0
DISTILLED (+)					7,050	10,070
EXPENDED (−)	20,200	200	100	0	6,400	8,570
GAIN (+) LOSS (−) BY INVENTORY	+150	0	0	0	0	0
ON HAND THIS REPORT	203,950	15,000	1,400	1,700	9,700	10,580
ON HAND %	92	76	70	100	94	91

POTABLE WATER RECORD		
PERSONNEL ON BOARD	GALLONS USED PER PERSON	STANDARD
243	26	27

FEEDWATER CONSUMPTION	
NOT UNDERWAY (gallons per hour)	UNDERWAY (gallons per hour)
	357

REMARKS:

Boiler water alkalinity and phosphates below normal low limits but within first ABL requirements. Chloride above MAX limit due to FWDCT contamination. Boiler was treated to restore alkalinity and phosphate prior to blowdown to remove contamination.

* Stripped 200 gal from JP-5 service tank.
* Gained 150 gal sounding tanks during heavy seas.

NAVSEA 9255/9 (6-94)(FRONT) NSN 0116-LF-018-2600

Figure 220-27-1 Treatment Log (Sheet 11 of 12)

FUEL AND WATER REPORT

HOURS SINCE INSPECTION

BOILER WATER CONDITIONS

RECORD THE BOILER WATER TEST RESULTS IN THE DESIGNATED SPACES. RESULTS NOT WITHIN LIMITS MUST BE CIRCLED IN RED AND EXPLAINED IN REMARKS ON THE FRONT OF THIS REPORT.

BOILER NO.	FIRE-SIDE	WATER-SIDE	LAST SAMPLE pH/ALK	LAST SAMPLE COND.	LAST SAMPLE PHOS-PHATE	LAST SAMPLE CHLOR-IDE	RANGE OF RESULTS pH/ALK	RANGE OF RESULTS COND.	RANGE OF RESULTS PHOS-PHATE	RANGE OF RESULTS CHLOR-IDE	HOURS STEAMED UNDER CONTAM-INATION	LAYUP CODE	DAYS UNDER LAYUP	HOURS SINCE BOTTOM BLOW-DOWN
1A	961.4	961.4	0.100	400	10.0	2.28	MAX 0.125	450	40.0	2.52	MOD 7.2	—	—	23.2
							MIN 0.025	50	12.5	0.12	SER 0			
1B	1077.1	1077.1	0.125	150	30.0	0.24	MAX 0.150	210	37.5	0.28	MOD 0	STM	11.2	14.5
							MIN 0.100	130	15.0	0.04	SER 0			
							MAX				MOD			
							MIN				SER			
							MAX				MOD			
							MIN				SER			
							MAX				MOD			
							MIN				SER			
							MAX				MOD			
							MIN				SER			
							MAX				MOD			
							MIN				SER			
							MAX				MOD			
							MIN				SER			
							MAX				MOD			
							MIN				SER			
							MAX				MOD			
							MIN				SER			
							MAX				MOD			
							MIN				SER			
							MAX				MOD			
							MIN				SER			

FEEDWATER CONDITIONS

SYSTEM	DISSOLVE OXYGEN (ppb) 1	2	3	4	epm CHLORIDE 1	2	3	4	FEEDWATER pH/HYDRAZINE 1	2	3	4
RANGE OF RESULTS	MAX 10				MAX 0.04				MAX 20			
	MIN 7.5				MIN 0.01				MIN 10			

BOILER WATER LIMITS

	TYPE A	TYPE B	CHELANT	HIDEOUT	AUX	WASTEHEAT
pH/ALK (epm)	10.2–10.6	9.8–10.2	0.10–1.00	9.2–10.3	0.10–0.50	0.05–0.25
[illegible]	800	400	500	300	600	500
PHOSPHATE(ppm)	50–120	25–60	10–40	10–30	50–100	25–75
CHLORIDE (epm MAX)	1.0	1.0	1.0	1.0	1.0	1.0

FEEDWATER LIMITS

	WITH MORPHOLINE TREATMENT	WITHOUT MORPHOLINE TREATMENT
DISSOLVED OXYGEN (ppb)	15 MAX	15 MAX
SALINITY INDICATOR (epm)	0.04 MAX	0.02 MAX
CONDUCTIVITY INDICATOR(µmho/cm)	6.0 MAX	3.0 MAX
pH	8.6 – 9.0	–
HYDRAZINE	–	10–40

BOILER LAYUP

LAYUP CODE	TIME LIMIT
DRY	
DES DESICCANT	UNLIMITED
HTD HEATED AIR	UNLIMITED
WET	
STM 150 psi STM. (SHIP)	30 DAYS
STS 150 psi STM. (SHORE)	30 DAYS
NIT NITROGEN	30 DAYS
DFT HOT DFW FILL	2 WEEKS
HYD HYDRAZINE	UNLIMITED
SN SODIUM NITRITE	UNLIMITED

PREPARED BY: (OIL KING)	REVIEWED: (MPA)	REVIEWED: (ENGINEER OFFICER)
JEF	TEJ	MH [illegible]

NAVSEA 9255/9 (6-94)(BACK) NSN 0116-LF-018-2600

Figure 220-27-1 Treatment Log (Sheet 12 of 12)

SECTION 28.

SUPPLY INFORMATION

220-28.1 MATERIALS, FORMS AND STOCK NUMBERS

220-28.2

The national stock numbers (NSN) contained in the following supply information were appropriate at the time this chapter was issued, but are subject to change. If a stock number is changed, the supply system will still process an order as long as the ordered item is clearly identified on the requisition (DD Form 1348M). It is essential that material which is obviously defective or suspected to be defective be reported promptly to the Supply Department regardless of the cost of the defective item. Material deficiencies are resolved more expeditiously and effectively where the users report the problems when discovered. If possible, the defective material, the container, associated requisition number, and shipping documentation should be returned to the Supply Department to enable thorough reporting. Afloat supply departments will make defective material reports in accordance with the Afloat Supply Procedures Manual (NAVSUP P-485, Chapter 4). Ashore supply departments will submit reports in accordance with the Supply Ashore Manual (NAVSUP P-485, Volume 2). A copy of the report will also be forwarded to Naval Sea Systems Command (NAVSEA) and NSWCCD-SSES.

NOTE

Ships should requisition items well in advance of material expiration date. To assure receipt of freshest stocks, use CONUS document identifier codes and advice code 2G.

220-28.3 SAMPLING EQUIPMENT.

Items of sampling equipment required, other than those provided with the feedwater dissolved oxygen testing equipment, are as follows:

SAMPLING EQUIPMENT

Item	NSN
Cooler, sample, boiler water	1H 4420-00-376-1545*[*]
Cooler, sample, DFT	1H 4420-00-376-1545*[*]
Bottle, polyethylene, screw cap, 1 qt	9G 8125-00-819-6085

[*]The same cooler is used for boiler water, desuperheated steam, and DFT.

220-28.4 BOILER WATER TESTING CABINET.

The boiler water testing cabinet shall be installed in the oil lab and provides all of the equipment required for the feedwater chloride test and the boiler water chloride and phosphate tests. A complete cabinet can be obtained under NSN 1H 6630-00-372-0839. The items included in the cabinet are as follows:

TEST CABINET CONTENTS

Quantity	Item	NSN
6	Rod, stirring, glass, 7 in long, 3/16 in dia	9L 6640-00-290-0154

TEST CABINET CONTENTS - Continued

Quantity	Item	NSN
1	Lubricant, stopcock (tube)	9G 9150-00-190-0923
1	Bottle, reagent, 1 liter (for nitric acid)	9L 6640-00-253-2495
1	Bottle, reagent, 1 liter (for mercuric nitrate)	9L 6640-00-702-2540
3	Buret, automatic zero, 10 ml capacity	9L 6640-00-264-6951
3	Aspirator bulb assembly (for filling burets)	1H 6640-00-291-1162
1	Cabinet	1H 6640-00-292-3679
1	Casserole, porcelain, white	9L 6640-00-412-8400
1	Cylinder, graduated, 100 ml capacity, TD	9L 6640-00-420-0000
1	Bottle, square, 8 oz	9G 8125-00-543-7699
3	Bottle, drop dispenser, 60 ml, plastic	9L 6640-01-077-2468
3	Stopper, 2 hole	9L 6640-00-935-1108

220-28.5 BOILER WATER TESTING CABINET STOCK CHEMICALS.

The stock chemicals required for the boiler water testing cabinet, are as follows:

STOCK CHEMICALS

Item	NSN
Methyl purple (methyl red - acid blue 5), bottle of 12 capsules	9G 6810-00-142-9290
Phenolphthalein, 100 g	9G 6810-00-223-7612
Isopropyl alcohol (isopropanol, 2-propanol)	9G 6810-00-227-0410
Nitric acid solution, 1.0 normal, 1 qt	9G 6810-00-270-9978
Mercuric nitrate solution, 0.5 normal, 4 oz	9G 6810-00-281-4163
Chloride indicator, bottle of 12 capsules	9G 6810-00-753-4907

NOTE

Isopropyl alcohol may also be labelled isopropanol or 2-propanol. It is used in preparing chloride indicator, methyl purple indicator, and phenolphthalein indicator. No substitute is authorized.

220-28.6 BOILER WATER CONDUCTIVITY TEST EQUIPMENT.

The equipment required for the conductivity test of boiler water, is as follows:

CONDUCTIVITY TEST EQUIPMENT

Quantity	Item	NSN
1	Thermometer, metal, dial type, 0°C to 100°C	9G 6685-00-663-8093
2	Bottle, square, 8 oz	9G 8125-00-543-7699
1	Meter, conductivity, SOLUBRIDGE, specific conductance of 40-8000 µmho/cm	9N 6625-00-620-4539
1	Cell, conductivity, dip type, cell constant of 2.0	1H 6630-00-620-4540

220-28.7 DISSOLVED OXYGEN TESTING KIT.

The testing kit provides all of the equipment required for the feedwater dissolved oxygen test. The complete kit is obtainable under NSN 9G 6635-01-044-6065. The items included in the kit are as follows:

OXYGEN TEST KIT

Quantity	Item	NSN
1	Ampoules, 0-40 ppb oxygen, box of 30	9L 6630-01-068-5210
1	Snapper	9Q 5120-01-090-5860
1	Comparator, 0-40 ppb	9L 6630-01-035-1864
1	Sampler, dissolved oxygen, glass	9L 6640-01-045-0821
1	Cot, finger, large	9L 6515-00-935-1194
1	Clamp, chain type	9L 6640-00-275-0723
1	Clamp, utility	9L 6640-01-035-6515
1	Tubing, neoprene, 3/16 in ID	9C 4720-00-529-5015

220-28.8 HYDRAZINE TEST KIT.

The hydrazine test kit provides the equipment required for the feedwater hydrazine test. The complete kit is obtainable under NSN 9G 6665-01-319-3149. The items included in the kit are:

Sample cup, 25 ml

Comparator, low range, 0-500 ppb

Comparator, high range, 0-100 ppm

Ampoules, hydrazine, box of 30

Replacement ampoules are also available as follows:

Item	NSN
Ampoules, hydrazine, box of 30	9G 6810-01-312-4075

220-28.9 EDTA HARDNESS TEST EQUIPMENT.

The following are the chemicals and equipment necessary for performing the EDTA Hardness Test:

Quantity	Item	NSN
1	Hardness titrating solution, EDTA 1 ml = 1 mg $CaCO_3$, 1 gal bottle	9G 6810-01-072-1978
1	Hardness buffer powder, 100 gram bottle	9G 6850-01-390-4335
1	Hardness indicator powder, 100 gram bottle	9G 6850-01-390-4339
3	Brass measuring dipper	9C 4410-01-077-2467
1	Squeezomatic buret assembly, 0-10 ml	1H 6640-01-072-1980
1	Dimethylglyoxime, crystal, ACS, 1 oz	9G 6810-01-082-5414

220-28.10 SILICA TEST KIT.

The following are replacement parts and reagents for the Silica Test Kit. The complete kit (without the graduated cylinder) is available under NSN 1H 4410-01-183-7442.

Quantity	Item	NSN
1	Sample cell holder, 1 cm	See AEL
2	Sample cell with cap	See AEL
1	Clippers, large	See AEL
1	Silica 1 reagent (sodium molybdate), 2 oz	9G 6810-01-169-1773
1	Citric acid powder pillows, 10 ml size, 100 pillows	9G 6810-01-169-6568
1	Amino acid reagent powder pillows, 10 ml size, 100 pillows	9G 6810-01-169-1770
1	Graduated cylinder, plastic, 100 ml, TD	9L 6640-00-889-7089

220-28.11 STANDARDS FOR VERIFICATION TESTING.

Stock chemicals, reagent chemicals, and conductivity equipment can deteriorate. Standards are available to check the accuracy of boiler water and feedwater test chemicals and equipment. The standards available for verification testing are as follows:

Item	NSN
Standard conductivity solution (1,400 µmho/cm)	9G 6810-00-945-7682
Standard chloride solution (2.0 epm)	9G 6810-01-129-3762
Standard hardness solution (0.2 epm)	9G 6810-01-125-5234
Standard methyl purple alkalinity (6.0 epm)	9G 6810-01-259-8231

220-28.12

All of the foregoing standards are supplied as solutions in small plastic bottles. All standard solutions must be discarded after one use. Quarterly verification testing is to be performed when a new reagent solution is prepared, and whenever the validity of a test result is in doubt.

220-28.13 TREATMENT CHEMICALS.

The treatment chemicals are as follows:

Item	NSN
Trisodium phosphate, dodecahydrate (25 lb drum) (O-S-642, Type II)	9G 6810-01-082-5415
Caustic soda (lye, sodium hydroxide, 500 g bottle)	9Q 6810-00-270-8177
Morpholine, 40 percent (5 gal can)	9G 6810-00-419-4298
Disodium phosphate (sodium phosphate dibasic, 25 lb drum) (O-S-639)	9G 6810-00-584-4298
Ion exchange resin	9G 6810-00-849-7811
Hydrazine, 7 percent (1 gal bottle)	9G 6810-01-304-5373
Trisodium EDTA (25 lb drum) (trisodium ethylenediaminetetraacetic acid trihydrate)	9G 6810-01-312-4076

220-28.14 SAFETY EQUIPMENT.

Protective equipment is required when handling corrosive materials such as acids or alkalies. Rubber gloves give long term protection; however, rubber gloves may not give positive control of an operation as do plastic gloves. Plastic gloves give better hand control but can be used only once. The average size for rubber gloves is 10 and for plastic gloves, medium. Useful equipment is as follows:

Item	NSN
Apron, synthetic rubber	9Q 8415-00-634-5023

Item	NSN
Face shield, industrial	9Q 4240-00-542-2048
Gloves, rubber	9D 8415-00-266-8677
Gloves, plastic	9D 8415-00-682-6786
Goggles, chemical safety	9G 4240-01-364-2169

220-28.15

The following protective equipment is specified for chelant treatment in addition to the above:

Apron, toxicological agents protective, (medium)	9D 8415-00-281-7814
Drum, shipping and storage sheet metal with enamel	9G 8110-00-254-5713
Foot wear covers, chemical protective	9D 8430-01-021-5978
Gloves surgical, natural, (size 8)	9L 6515-00-339-7880
Plastic bag	9Q 8105-00-200-0195
Spill absorbent (50 lb)	9Q 7930-00-269-1272

220-28.16 MISCELLANEOUS MATERIAL.

Miscellaneous material that is useful in treatment and in testing is as follows:

Item	NSN
Bottle, drop-dispenser, plastic, 60 ml	9L 6640-01-077-2468
Bottle, wash, laboratory, plastic (500 ml)	9L 6640-00-314-2097
Desiccant, 1 lb bags or 1/2 lb bags	9G 6850-00-264-6572 or 9G 6850-00-264-6571
Humidity indicator card, can of 125	9G 6685-00-752-8240
Jerrican, polyethylene, screw cap, 5 gallons	9L 6640-01-083-9756
Jug, polyethylene, safety dispensing, screw cap, 2 1/2 gallons	9L 6640-01-083-9755
Scale, 16 lb, with counter weights	9G 6670-00-641-3485
Scale, 24 oz capacity	9G 6670-00-937-2690
Scoop, plastic, 2 inch bowl	9Q 7330-01-079-0694
Sodium nitrite, ACS grade, 5 lb	9G 6810-00-270-3254
Spatula, laboratory, nickel-plated steel	9L 6640-00-171-5198
Stopper, solid rubber, 1 lb (approx 13) size 9	9L 6640-00-935-1108

220-28.17 ALLOWANCE EQUIPAGE AND PARTS LIST

220-28.18

The following allowance equipage and parts lists apply to test and treatment of propulsion boiler water and feedwater:

1. AEL 2-560004101, Kit, Boiler Water/Feedwater Test and Treatment
2. AEL 2-560004102, Meter, Conductivity Test of Boiler Water.
3. AEL 2-560004103, Chemicals and Equipment, Boiler Water/Feedwater Test and Treatment (Quantities based on the number of boilers).
4. AEL 2-560004104, Chemicals and Equipment, Boiler Water/Feedwater Test and Treatment (Quantities based on boiler water treatment volume).

5. AEL 2-560004055, Kit, Dissolved Oxygen Test of Feedwater.

6. APL 619990402, Continuous Automated Treatment System.

7. AEL 560004109, Chemicals and Equipment, Chelant Boiler/Feedwater Test and Treatment

8. AEL 2-560004108, Silica Test Kit.

220-28.19

AEL and APL quantity changes are updated by the ship by forwarding a change request to SPCC Mechanicsburg, PA.

220-28.20 MATERIAL CONTROL

220-28.21

Control of the material required for testing and treatment of feedwater and boiler water is necessary. An adequate supply must be maintained, stored properly, and have remaining shelf life.

220-28.22 RECOMMENDED ONBOARD STOCK.

Recommended onboard stock for laboratory test equipment and test and treatment chemicals required for a normal six month deployment is listed in Table 220-28-1 for chelant treated main propulsion boilers. Similar tables are included in Section 29, Section 30, and Section 31 for auxiliary, waste heat and COPHOS treated main propulsion boilers. Actual ship usage may vary. If actual shipboard usage based on historical data is greater than the quantities listed in the tables, the actual usage shall be used as the onboard requirement. A monthly inventory of test and treatment chemicals is required to ensure maintenance of sufficient onboard supplies of in date material. At the end of each month record the following information for each applicable chemical listed in the Boiler Water/Feedwater Test and Treatment Chemical Inventory Log (Figure 220-27-1, sheets 3 and 4):

a. The quantity onboard with less than six months shelf life remaining. Do not record expired material.

b. The quantity onboard with six or more months shelf life remaining.

c. The minimum onboard stock required for a six month deployment.

d. Determine if the quantities onboard are sufficient, by recording yes or no in the sufficient onboard stock column. If the quantity onboard is not sufficient, the ″no″ entry shall be circled in the log.

The completed inventory log shall be included as part of the monthly water treatment log package. Items listed on the log that are not ship applicable may be lined out.

220-28.23 MATERIAL STORAGE.

Nitric acid and mercuric nitrate stock solutions shall be stored in the original packing in chemical resistant metal chests or lockers (normally located in the test laboratory). All chemicals are to be stored in areas where the temperature does not exceed 38°C (100°F). Spare glassware should be cushioned in storage to avoid breakage. Hydrazine and dissolved oxygen ampoules shall be stored in their box away from direct light. The ampoules deteriorate with exposure to light. The 7 percent hydrazine solution shall be stored only in the dedicated safety storage locker(s) in individual firerooms.

220-28.24 SHELF LIFE.

Stock solutions, indicators, and standards are subject to deterioration during storage. For this reason various shelf lives have been imposed on these materials to minimize errors in testing boiler water and feedwater. The shelf life of a material is measured from its date of manufacture. It is recommended that shelf life control procedures be established and maintained. Items received without date of manufacture or expiration shall be marked with an expiration date based on the date of receipt.

Table 220-28-1 RECOMMENDED ONBOARD STOCK FOR 6-MONTH DEPLOYMENT

Item	NSN	Unit of Issue	Qty	Notes
BASIC EQUIPMENT				
Boiler water testing cabinet (complete)	1H 6630-00-372-0839	EA	1	[b]
Boiler water conductivity test equipment (complete)	All items in 220-28.6	N/A	1 set	[b]
Cabinet, storage hydrazine	1HS 0000-LL-CQA-2208	EA	1	[c]
Dissolved oxygen testing kit (complete)	9G 6635-01-044-6065	KT	1	[c]
Hardness test equipment	All items in 220-28.9	N/A	1	[b]
Hydrazine test kit	9G 6665-01-319-3149	KT	1	[c]
Locker, clothing, safety equipment	9Q 7125-00-530-1899	EA	1	[c]
Silica Test Kit	1H 4410-01-183-7442	KT	1	[b]
STOCK CHEMICALS				
Amino acid reagent pillows	9G 6810-01-169-1770	BT (100)	1	[b]
Ampoules, 0-40 ppb oxygen	9L 6630-01-068-5210	PG (30)	7	[c]
Ampoules, hydrazine	9G 6810-01-312-4075	BX (30)	7	[c]
Chloride indicator capsules	9G 6810-00-753-4907	BT (12)	1	[a]
Citric acid reagent pillows	9G 6810-01-169-6568	BT (100)	1	[b]
Dimethylglyoxime	9G 6810-01-082-5414	BT (25 g)	1	[a]
Hardness buffer	9G 6850-01-390-4335	BT (100 g)	1	[a]
Hardness indicator	9G 6850-01-390-4339	BT (100 g)	1	[a]
Hardness titrating solution	9G 6810-01-072-1978	GL	1	[a]
Isopropyl alcohol (isopropanol, 2-propanol)	9G 6810-00-227-0410	GL	1	[a]
Mercuric nitrate	9G 6810-00-281-4163	BT (4 oz)	3	[a]
Methyl purple indicator capsules	9G 6810-00-142-9290	BT (12 per btl)	1	[a]
Nitric acid	9G 6810-00-270-9978	QT	1	[a]
Phenolphthalein indicator	9G 6810-00-223-7612	1 BT (100 g)	1	[a]
Silica-1 reagent	9G 6810-01-169-1773	BT (2 oz)	1	[b]
STANDARDS				
Chloride (2.0 epm)	9G 6810-01-129-3762	BT (75 ml)	12	[b]
Conductivity (1,400 µmho/cm)	9G 6810-00-945-7682	BT (250 ml)	12	[b]
Hardness (0.2 epm)	9G 6810-01-125-5234	BT (150 ml)	8	[b]
Methyl purple alkalinity (6.0 epm)	9G 6810-01-259-8231	BX (6-100 ml btl)	2	[a]

Table 220-28-1 RECOMMENDED ONBOARD STOCK FOR 6-MONTH DEPLOYMENT - Continued

Item	NSN	Unit of Issue	Qty	Notes
TREATMENT CHEMICALS				
Caustic soda (lye, sodium hydroxide)	9Q 6810-00-270-8177	CO (500 g)	4	[a]
Desiccant, 1 lb bag	9G 6850-00-264-6572	DR (150 bags)	2	[a]
Desiccant, 1/2 lb bag	9G 6850-00-264-6571	DR (300 bags)	2	[a]
Disodium phosphate anhydrous (sodium phosphate, dibasic, O-S-639)	9G 6810-00-584-4298	DR (25 lb)	4	[a]
Humidity Indicator Card	9G 6685-00-752-8240	CN (125)	2	[a]
Hydrazine, 7% (carriers excluded)	9G 6810-01-304-5373	BT (1 gal)	30	[c]
Hydrazine, 7% (carriers)	9G 6810-01-304-5373	BT (1 gal)	60	[c]
Ion exchange resin (carriers excluded)	9G 6810-01-849-7811	CF	12	[d], [e]
Ion exchange resin (carriers)	9G 6810-01-849-7811	CF	48	[d], [e]
Morpholine, 40%	9G 6810-00-419-4298	CN (5 gal)	1	[a]
Nitrogen	9G 6830-00-656-1596 or 9G 6830-00-244-2741	CY (1 cylinder)	3	[c]
Trisodium EDTA, trihydrate	9G 6810-01-312-4076	DR (25 lb)	4	[a]
Trisodium phosphate dodecahydrate (sodium phosphate, tribasic, dodecahydrate, O-S-642, Type II)	9G 6810-01-082-5415	DR (25 lb)	6	[a]
SAFETY EQUIPMENT				
Apron, rubber	9D 8415-00-634-5023	EA	1	[a]
Apron, toxicological	9D 8415-00-281-7814	EA	2	[c]
Drum, shipping and storage	9G 8110-00-254-5713	EA	1	[c]
Face shield	9Q 4240-00-542-2048	EA	2	[a]
Finger cot	9L 6515-00-935-1194	PG (144)	2	[c]
Foot wear covers, chemical protective	9D 8430-01-021-5978	PR	2	[c]
Gloves, chemical protective	9D 8415-00-266-8677	PR	6	[a]
Gloves, plastic	9D 8415-00-682-6786	PR	100	[a]
Gloves, surgeons	9L 6515-00-339-7880	PR	100	[c]
Goggles, chemical safety	9G 4240-01-364-2169	PR	2	[a]
Plastic bag	9Q 8105-00-200-0195	BX (100)	1	[b]
Spill absorbent	9Q 7930-00-269-1272	BG (50 lb)	1	[c]
SPARE EQUIPMENT				
Aspirator bulb assembly (for filling burets)	1H 6640-00-291-1162	EA	3	[b]
Bottle, dropper, 60 ml plastic	9L 6640-01-077-2468	PG (12)	1	[b]
Bottle, polyethylene, screw cap, 1 qt	9G 8125-00-819-6085	EA	12	[a]
Bottle, reagent, 1 liter (for nitric acid)	9L 6640-00-253-2495	EA	1	[b]

Table 220-28-1 RECOMMENDED ONBOARD STOCK FOR 6-MONTH DEPLOYMENT - Continued

Item	NSN	Unit of Issue	Qty	Notes
Bottle, reagent, 1 liter (for mercuric nitrate)	9L 6640-00-702-2540	EA	1	b
Bottle, 8 oz, square	9G 8125-00-543-7699	EA	2	b
Bottle, wash, plastic, 500 ml	9L 6640-00-314-2097	EA	3	b
Buret assembly, automatic zero, 10 ml, for hardness	1H 6640-01-072-1980	EA	3	b
Buret, automatic zero, 10 ml, for chloride and phosphate	9L 6640-00-264-6951	EA	3	b
Casserole, porcelain, white	9L 6640-00-412-8400	EA	2	b
Cell, conductivity, dip type, constant of 2.0	1H 6630-00-620-4540	EA	1	b
Comparator, 0-40 ppb oxygen	9L 6630-01-035-1864	EA	1	c
Cooler, sample, boiler water	1H 4420-00-376-1545*	EA	2	b
Cooler, sample, DFT	1H 4420-00-376-1545*	EA	1	b
Cylinder, graduated, 100 ml (glass), TD	9L 6640-00-420-0000	EA	5	b
Cylinder, graduated 100 ml (plastic), TD	9L 6640-00-889-7089	EA	5	b
Dipper, brass	9C 4410-01-077-2467	EA	4	b
Grease, ground glass joint	9G 9150-00-965-2408	TU (150 g)	1	b
Jerrican, plastic, 5 gal	9L 6640-01-083-9756	EA	1	a
Jug, safety, plastic, 2 1/2 gal	9L 6640-01-083-9755	EA	1	a
Meter, conductivity Solubridge	9N 6625-00-620-4539	EA	1	b
Rod, stirring, 7 in long	9L 6640-00-290-0154	EA	6	b
Sampler, glass, dissolved oxygen	9L 6640-01-045-0821	EA	4	c
Scale, 16 lb cap	9G 6670-00-641-3485	EA	1	b
Scale, 24 oz cap	9G 6670-00-937-2690	EA	1	b
Scoop, plastic	9Q 7330-01-079-0694	DZ	1	b
Snapper, dissolved oxygen	9Q 5120-01-090-5860	EA	5	c
Spatula, nickel-plated steel	9L 6640-00-171-5198	EA	1	b
Stopper, 2-hole and solid rubber, size 9	9L 6640-00-935-1108	PG (15)	1	b
Thermometer, metal, dial type (0 to 100°C)	9G 6685-00-663-8093	EA	3	b
Tubing, neoprene, 3/16 in ID, dissolved oxygen	9C 4720-00-529-5015	FT	3	c

[b]Quantity needed per ship

[c]Quantity needed per DFT

[a]Quantity needed per two boilers

[d]Applies only to ships with demineralizers installed

[e]Per demineralizer

220-28.25

All stock chemicals, standards, dissolved oxygen comparator, and hydrazine comparator have a 2-year shelf life, except as follows:

Item	Months of Shelf Life
Chloride indicator (capsules, from date of manufacture)	36
Chloride indicator (prepared solution, from date of preparation)	9
Dimethylglyoxime (DMG)	Unlimited
Hydrazine Ampoules	60
Isopropyl alcohol	Unlimited
Methyl purple indicator (capsules, from date of manufacture)	Unlimited
Methyl purple indicator (prepared solution, from date of preparation)	6
Phenolphthalein indicator	Unlimited
Silica-1 reagent (from date of receipt)	12

220-28.26

Mixed bed ion exchange resin has a shelf life of 24 months. Do not use ion exchange resin that has been exposed to a temperature of 0°C (32°F) or less. All of the remaining treatment chemicals have an indefinite shelf life.

220-28.27

All stock chemicals should be visually examined when received. Cloudy solutions or deposits in the bottom of the bottle indicate deterioration. The caps of the liquid standards, by specification, must be sealed with plastic to prevent evaporation of liquid, prior to use.

220-28.28 FORMS.

The following forms are used to record water conditions for ships using chelant boiler feedwater treatment. They may be obtained through normal supply channels in accordance with NAVSUP Publication 2002.

1. NAVSEA 9255/14 (6-94), NSN 0116-LF-018-2800, Chelant Treatment Feedwater Chemistry Worksheet/Log

2. NAVSEA 9255/6 (6-94), NSN 0116-LF-018-2300, Cover Sheet and Monthly Boiler Data

3. NAVSEA 9255/15 (6-94), NSN 0116-LF-018-2900, Chelant Treatment Boiler Water Chemistry Worksheet/Log

4. NAVSEA 9255/9 (6-94), NSN 0116-LF-018-2600, Fuel and Water Report

5. NAVSEA 9255/10 (6-94), NSN 0116-LF-018-8700, Reserve/Makeup Feedwater Tests Log

6. NAVSEA 9255/16 (6-94), NSN 0116-LF-018-3100, Boiler Water/Feedwater Test and Treatment Chemical Inventory Log

SECTION 29.

WATER REQUIREMENTS FOR AUXILIARY BOILER SYSTEMS

220-29.1 INTRODUCTION.

This section provides water treatment procedures for auxiliary boilers. Auxiliary boilers are low pressure, oil fired boilers that provide steam for the ship's service steam system. The water requirements for the waste heat boilers are given in Section 30.

220-29.2

The water requirements for the auxiliary boilers are divided into two broad classes based on whether the vessel has propulsion boilers or not. Paragraphs 220-29.4 through 220-29.89 apply to the auxiliary boilers in ships not equipped with main propulsion boilers. The water requirements for the auxiliary boilers in ships with main propulsion boilers are based on the propulsion boiler water requirements. The differences between the main propulsion boiler requirements and the auxiliary boiler water requirements for these ships are given at the end of this section, paragraphs 220-29.90 through 220-29.116. This section does not apply to ships with nuclear main propulsion. For these ships, refer to the steam plant manual for auxiliary boiler water requirements.

220-29.3 WATER REQUIREMENTS FOR AUXILIARY BOILERS IN SHIPS EQUIPPED WITH DIESEL MAIN PROPULSION

220-29.4 AUXILIARY BOILER STEAM PLANT WATER CHEMISTRY.

In general the principles of water chemistry control given in Section 21 apply to the auxiliary boiler system. Information specific to auxiliary boilers follows.

220-29.5 AUXILIARY BOILER SYSTEM WATER CYCLE.

The overall auxiliary boiler system water cycle is a closed system in which feedwater from the boiler feedwater tank is pumped to the boiler, the boiler water is heated to generate steam and the steam is used for ship's services. The steam drains are condensed by the condensate/drain cooler and returned to the feedwater tank/fresh water drain collecting tank (FWDCT). Water for the cycle is obtained from the evaporation of seawater by the distiller. The distillate is usually sent to a reserve feedwater tank. The reserve feedwater is then added as makeup feedwater to the feedwater tank to replace water that is lost from the system due to boiler blowdown and system leaks.

220-29.6 AUXILIARY BOILER WATER FLOW

220-29.7 FIRE-TUBE.

The fire-tube boilers comprise the largest population of auxiliary boilers. These boilers are found on mine sweepers, auxiliary ships, some nuclear powered cruisers and service craft. Fire-tube boilers are small, single drum boilers. The hot combustion gases make two or more passes through submerged tubes to provide the heat to generate the steam. The steam rises, enters the dry pipe/pan, and leaves the boiler by way of the steam outlet valve. Any sediment settles in the bottom of the drum. The boilers are equipped with surface and bottom blowdown connections. The boiler is fired automatically to maintain the operating pressure.

220-29.8 NATURAL CIRCULATION WATERTUBE.

Most of the natural circulation watertube auxiliary boilers are on the LST 1179 Class and LSD 41 Class ships. They are also on some AS, AO and LSD Class ships. Watertube auxiliary boilers consist of a steam drum and a water drum connected by tubes. The hot combustion gases heat the water in the tubes. The steam/water mixture rises to the steam drum where the steam is separated from the water by baffles. The steam exits the boiler by way of the dry pipe. Feedwater enters the boiler through the feed pipe. The relatively cool water in the steam drum descends to the water drum by way of water tubes and downcomers. The water drum distributes the water to the generating tubes. The boilers are equipped with surface and bottom blowdown connections.

220-29.9 FEEDWATER CONTAMINANTS.

Maintaining good quality feedwater is essential to effective control of the water chemistry. The water conditions must be controlled within the allowable limits to prevent waterside corrosion, scale formation, and carry-over.

220-29.10

In a properly operating auxiliary boiler system the distillate contains the highest level of contaminants. Therefore, the makeup rate will determine the amount of contaminant that enters the boiler. High makeup rates will cause the boiler water chloride and conductivity to increase, and lead to a higher usage of treatment chemicals. This will cause greater sludge formation and an increase in the deposits on the watersides. The makeup rate shall be maintained at a minimum by correcting all system leaks.

220-29.11 SEAWATER.

Seawater is the most common contaminant found in marine boiler water systems. The primary source of seawater contamination is a tube leak in the condensate cooler. A small leak in the cooler can be difficult to locate. Methods for tube leak testing are given in **NSTM Chapter 254, Condensers, Heat Exchangers, and Air Ejectors** . The following summarizes the sources, detection methods, effects and corrective action required for seawater contamination:

1. **Source**
   a. Distillate; dump valve malfunctioning or bypassed
   b. Condensate/Drain cooler; tube leak
2. **Detection**
   a. Salinity/conductivity indicators
   b. Chemical chloride test
3. **Effect on boiler water**
   a. Alkalinity decreases
   b. Phosphate decreases
   c. Conductivity increases
   d. Chloride increases
4. **Corrective action**
   a. Find, isolate, and correct source of contamination.
   b. Sample and test boiler water as necessary to keep alkalinity and phosphate within limits.
   c. Blowdown to remove contamination.

d. The most effective method to remove high levels of contamination from the boiler is to secure, cool, dump and flush.

220-29.12 SHORE WATER.

Shore water contamination is caused by either shore potable water entering the feedwater system or by the use of contaminated shore source feedwater or steam. The feedwater hardness test is used to detect shore water contamination. The salinity/conductivity indicator readings will increase when shore water contamination is occurring. The feedwater chemical chloride test result will be lower than the chloride level indicated by the salinity/conductivity indicators. The effects of shore water contamination will stop after a few days at sea as the shore source water is replaced with distillate. The usual source of shore potable water contamination is through a leak in a hot water heater steam coil. The source of a small leak can be difficult to find. Monitoring the salinity/conductivity indicators and the condensate hardness while each heater is secured for 30 minutes and then placed back in service will help indicate the source. The following summarizes the sources, detection methods, effects and corrective action for shore water contamination:

1. **Source**
   a. Hot water heaters; leaking steam coil
   b. Galley and laundry equipment; leak or malfunction
   c. Shore source feedwater; contaminated
   d. Shore steam; contaminated
2. **Detection**
   a. Salinity/conductivity indicator
   b. Feedwater hardness test
3. **Effect on boiler water**
   a. Alkalinity will increase
   b. Phosphate will decrease
   c. Conductivity will usually increase
   d. Chloride will usually increase
4. **Corrective action**
   a. Find, isolate, and correct source of contamination.
   b. Sample and test boiler water as necessary to keep alkalinity and phosphate within limits.
   c. Blowdown to remove contamination.
   d. The most effective method to remove high levels of contamination from the boiler is to secure, cool, dump and flush.

220-29.13 OIL.

The steam can become contaminated with oil if a leak occurs at a lubricating oil heater. Oil entering the feed system will coat the salinity/conductivity cell electrodes causing erroneous low readings. The cells must be cleaned with alcohol to remove the oily film. Oil contamination of the boiler can be seen in the gauge glass. The following summarizes the sources, detection methods, effects and corrective actions for oil contamination:

1. **Source**
   a. Lubricating oil heater; leak

2. **Detection**
   a. Oily condensate in inspection tank
   b. Oil in the feedwater or boiler water sight glass
   c. Oil in the feedwater or boiler water samples
3. **Effect on boiler water chemistry**
   a. No effect on alkalinity, phosphate, conductivity or chloride
   b. May induce carryover
4. **Corrective action**
   a. Find, isolate, and correct source of contamination.
   b. Surface blow to remove contamination, treat as necessary to keep alkalinity and phosphate within limits if boiler is steaming.
   c. If contamination is severe, then clean boiler with an alkaline boil out in accordance with **NSTM Chapter 221, Boilers** .

220-29.14 DISSOLVED OXYGEN.

Dissolved oxygen causes corrosion of the auxiliary boiler system steel. Water in contact with air will absorb oxygen and other gases. The amount of oxygen that can be dissolved in water is dependent on the temperature of the water, the hotter the water the lower the dissolved oxygen. Auxiliary boilers do not use any method of oxygen removal or testing. The corrosion due to dissolved oxygen is kept as low as possible by maintaining the feedwater as hot as the system permits. Oxygen corrosion also occurs during idle periods if oxygen is allowed to enter the boiler. Proper layup is essential to prevent this corrosion.

NOTE

NSTM Chapter 221 requires that the steam used for propulsion boiler layup be produced from boilers that operate on deaerated feedwater. Therefore the auxiliary boilers cannot provide steam for propulsion boiler layup.

220-29.15 OTHER CONTAMINANTS.

Other contamination sources are:

1. Metal corrosion products and suspended solids. Corrosion products from the feedwater system are washed to the boiler. To some extent erosion of the feedwater system metal surfaces also contributes suspended matter to the boiler water. These particles contribute to the formation of sludge in the boiler water. This will be most noticeable after long idle periods and will be indicated by discoloration of the boiler water. Extra blowdowns or securing and dumping will be required to remove the sediment from the boiler.
2. Preservatives. Metal preservative coatings are used to protect the metal surfaces after manufacture. The preservative is usually removed prior to shipboard installation. The contaminant is usually found only in new ships where the preservative has not been properly removed. Contamination can also occur when piping is replaced without removing the preservative from the new component. When the boiler is steamed, the preservative that is washed to the boiler will bake onto the boiler tubes. Preservative contamination is removed using an alkaline boilout in accordance with NSTM Chapter 221.
3. Dirt and Debris. Whenever the auxiliary boiler system is open for repair or maintenance, care must be taken to prevent dirt from entering the system. Dirt and debris that has entered the system will contribute to the sus-

pended matter in the boiler water and may increase the waterside deposits. The effects will be seen when the auxiliary boiler is first lit off. The boiler water sample will be dark and may be difficult to test. The boiler water chemistry may be affected. Extra blowdowns or securing and dumping will be required to remove the sediment.

220-29.16 REQUIREMENTS FOR AUXILIARY BOILER FEEDWATER IN SHIPS EQUIPPED WITH DIESEL MAIN PROPULSION

220-29.17

The feedwater requirements for auxiliary boilers are based on the actual values attainable for a properly operated system. The feedwater limits are the maximum allowed. Whenever the feedwater test results exceed the limits, either by chemical test or by salinity/conductivity indicator, the source of the contamination must be located and corrective action taken. The values should be maintained at the lowest levels for routine control of the boiler water. The limits are summarized in Table 220-29-1.

220-29.18 SALINITY/CONDUCTIVITY INDICATORS.

All installed feedwater salinity/ conductivity indicating devices shall be monitored for any signs of contamination. The salinity/ conductivity indicators give the first warning of contamination and corrective action is taken as soon as the contamination is detected. Salinity/conductivity indicator alarms and dump valves shall be set as close to the limit as the installed hardware permits. Replacement or modification of the hardware is not authorized or required by this chapter.

220-29.19

Salinity indicators and conductivity indicators both measure the conductivity of the water. Salinity indicators are labeled to read in epm chloride or ppm chloride (1 epm = 35.5 ppm). If contamination from other than a seawater source is present the salinity/conductivity indicators will read higher than the chemical chloride test.

220-29.20

Continuous monitoring of either boiler feedwater or all condensate contamination sources by salinity or conductivity indicators is required to ensure maintenance of boiler water quality. If auxiliary boiler feedwater or condensate quality is not continuously monitored by salinity or conductivity indicators installed in either all condensate streams or in the feedwater piping, boiler water shall be sampled and tested every four hours. When individual salinity/conductivity indicators are not operational, except reserve feedwater, either sample the affected feedwater and chemically test for chloride every four hours or sample and test boiler water every four hours. If reserve feedwater cannot be continuously monitored, test for chloride 30 minutes prior to use.

220-29.21 CHEMICAL TESTS AND SALINITY/CONDUCTIVITY INDICATOR COMPARISON.

The salinity/conductivity indicators that monitor condensate (excluding distiller air ejector drains), feedwater, and distillate shall be checked daily when in use to ensure satisfactory operation. Ships equipped with conductivity indicators reading out in µmho/cm and ships with salinity indicators reading out in ppm are required to convert the readings to epm chloride prior to making the comparison. To convert a conductivity indicator reading in µmho/cm to epm chloride, divide the conductivity reading by 145. To convert a salinity indicator reading in ppm to epm chloride, divide the salinity reading by 35.5. This check shall be made by comparing the chemical test result for feedwater chloride to the salinity/conductivity indicator reading (measured in or converted to epm chloride). The sample shall be obtained from a sample connection near the cell or from a feedwater tank that is representative of the water. Sampling of the water and reading of the salinity/conductivity indicator is accomplished concurrently:

Table 220-29-1. AUXILIARY BOILER FEEDWATER REQUIREMENTS

Source	Maximum Limit			
	Conductivity Indicator µmho/cm	**Salinity Indicator epm (ppm)**	**Chemical Chloride epm**	**Chemical Hardness epm**
Distillate	10.0	0.065 (2.3)	0.07	----
Distiller Air Ejector Drains	10.0	0.065 (2.3)	0.05	----
Reserve Feedwater/Makeup Feedwater	15.0	0.100 (3.5)	0.10	0.10
Feedwater/Condensate/Drains	8.0	0.050 (1.8)	0.05	0.02

Source	Test Frequency
All distillate, condensate, and feedwater monitored by salinity indicators.	Perform daily comparison test on all salinity indicators that can be sampled (except distiller air ejector drains).
	Monitor indicators whenever system component is operating.
	When indicator is malfunctioning, test the water that is monitored by the affected indicator for chloride every 4 hours or test boiler water every 4 hours.
Distiller air ejector drains	Test for chloride daily.
	When indicator malfunctions or indicates an out of limits condition, test for chloride every 4 hours. Drains may be used based on chemical chloride test.
Reserve and makeup feedwater	Test all feedwater tanks for chloride and hardness within 24 hours prior to light off of a cold plant.
	For cold plant start-up, test reserve feedwater for chloride within 30 minutes prior to use.
	Monitor makeup feedwater salinity indicator whenever system is operating.
	When indicator is faulty, test reserve feedwater tank for chloride within 30 minutes prior to use.

NOTE

Salinity indicator alarm and dump valves shall be set as close to the above limits as installed hardware permits. Replacement or modification of installed hardware is not authorized or required by this chapter. Updating of these systems is only approved by ship alteration as authorized by the Type Commander and NSWCCD.

1. If the difference between the chemical test result and the indicator reading is 0 ± 0.02, the comparison is satisfactory.

2. If the chemical test result is higher than the indicator reading by more than 0.02, the comparison is unsatisfactory and the indicator must be checked for malfunction (paragraph 220-24.70).

3. If the chemical test result is lower than the indicator reading by more than 0.02 epm, check the water for

hardness (excluding distillate)* . If hardness is 0.02 epm or less, check the indicator for malfunction. If hardness is more than 0.02 epm, the indicator is functioning satisfactorily.

4. An indicator that consistently reads zero shall be checked for malfunction.

NOTE

Salinity or conductivity indicator readings higher than chemical chloride may also occur due to the presence of dissolved gases when operating in coastal, river, bay or port waters, or due to volatile chemicals following hydrazine layup or use of shore steam. If high salinity/conductivity indicator readings for distillate or distiller air ejector drains continue in the absence of high chemical chloride when operating in coastal, river, bay or port waters for extended periods, the following applies:

a. Test for chemical chloride every four hours.
b. Use of the water is based on chemical chloride.
c. Salinity/conductivity indicator limit/alarm set point/dump set point may be set to a value just above the distillate/air ejector drain salinity/conductivity. Record time/alarm set point in Remarks section of Feedwater Log.
d. Reset salinity/conductivity indicator limit/alarm set point/dump set point to normal values when indicator readings return to normal limits. Record in the remarks section of the feedwater log.

220-29.22 DISTILLATE.

On most vessels the distillate is monitored continuously by a salinity or conductivity indicator at the discharge of the distilling unit. The limit is 0.065 epm (2.3 ppm) chloride by salinity indicator or 10 µmho/cm by conductivity indicator. The indicator controls a solenoid valve which dumps the distillate if the limit is exceeded. The daily comparison test will assure that the cell is reading correctly. The limit by chemical test for distillate discharging to feed are 0.07 epm chloride.

220-29.23 IDLE FEEDWATER TANKS.

All feedwater tanks shall be sampled and tested for chloride and hardness within 24 hours prior to light off of a cold plant. The limits by chemical test are 0.10 epm chloride and 0.10 epm hardness. If distillate or shore source feedwater is required prior to light off, the tank samples shall be obtained after the tanks have been filled. Water exceeding these limits shall be dumped.

220-29.24 RESERVE AND MAKEUP FEEDWATER.

Vessels having a salinity or conductivity indicator in the discharge from the reserve feedwater tank shall monitor the makeup feedwater tank for any signs of contamination. The limit is 0.10 epm (3.55 ppm) chloride by salinity indicator or 15 µmho/cm by conductivity indicator. The daily comparison test will assure that the cell is operating properly. The limits by chemical test are 0.10 epm chloride and 0.10 epm hardness. For cold plant startup obtain a sample of the reserve feedwater within 30 minutes prior to light off and test for chloride. As soon as the tank is placed on makeup read the indicator and perform the comparison test. Reserve feedwater not meeting the requirements shall be dumped.

*The comparison test for distillate is based only on chemical chloride because the hardness test may give false high results. If the chemical chloride test result is lower than the indicator reading by more than 0.02 epm, check the indicator for malfunction.

220-29.25 FEEDWATER.

Vessels having a salinity or conductivity indicator in the discharge of the feedwater tank shall monitor the feedwater for any signs of contamination. The limit is 0.05 epm (1.8 ppm) chloride by salinity indicator or 8 µmho/cm by conductivity. The daily comparison test will assure that the cell is operating properly. The limits by chemical test are 0.05 epm chloride and 0.02 epm hardness. The feedwater may be above the limits for approximately 1 hour after light-off due to the higher limit for feedwater in an idle tank.

220-29.26 CONDENSATE AND DRAINS.

Vessels having a salinity or conductivity indicator in the discharge of the condensate/drain cooler shall monitor the condensate for any signs of contamination. The limit is 0.05 epm (1.8 ppm) chloride by salinity indicator or 8 µmho/cm by conductivity. The daily comparison test will assure that the cell is operating properly. The limits by chemical test are 0.05 epm chloride and 0.02 epm hardness.

220-29.27 DISTILLER AIR EJECTOR DRAINS.

The chloride limit by chemical test for distiller air ejector drains is 0.05 epm. Carbon dioxide gas removed from the distilling unit can dissolve in the air ejector drains causing the salinity or conductivity readings to be higher than the actual chloride content. Therefore, the limit by salinity indicator is 0.065 epm or by conductivity indicator is 10 µmho/cm. The daily salinity/conductivity comparison test is not required. The high bicarbonate level can also interfere with the hardness test giving false high results. The hardness test is not accomplished on distiller air ejector drains. A chemical chloride test of distiller air ejector drains is required daily and every four hours if the salinity/conductivity indicator malfunctions or indicates an out of limits condition. Use of distiller air ejector drains is based on the chemical chloride test.

220-29.28 SHORE SOURCE FEEDWATER.

Feedwater from a shore source shall meet the requirements of paragraphs 220-22.18 through 220-22.22. Documentation certifying that the water meets these requirements shall be obtained from the supplying facility or contractor. Ship's force shall sample and test each shipment of shore source feedwater prior to acceptance and each tank that receives water for compliance with the following requirements:

Test	**Requirement**
Hardness	0.10 epm
Conductivity	less than 40 µmho/cm*

*The lowest reading on the shipboard conductivity meter is 40 µmho/cm.

220-29.29 REQUIREMENTS FOR AUXILIARY BOILER WATER IN SHIPS EQUIPPED WITH DIESEL MAIN PROPULSION

220-29.30

The chemical treatment used for auxiliary boilers is designed to prevent acid corrosion, caustic corrosion, scale formation and carryover. The treatment is a coordinated phosphate treatment. Additional information on coordinated phosphate treatment is provided in Section 31. The auxiliary boiler limits are listed in Table 220-29-2.

Table 220-29-2. AUXILIARY BOILER WATER CONTROL LIMITS

Conductivity	600 µmho/cm maximum
Alkalinity	0.10 to 0.50 epm
Phosphate	50 to 100 ppm
Chloride	1.0 epm maximum

220-29.31

Trisodium phosphate and disodium phosphate are the chemicals used to treat the auxiliary boiler water. Trisodium phosphate provides alkalinity and some of the phosphate. The disodium phosphate provides additional phosphate while contributing little to the alkalinity. Maintaining alkaline boiler water prevents acid corrosion and is necessary for the reaction between the phosphate and the scale formers. The additional phosphate prevents the formation of free caustic in the boiler water which could lead to caustic corrosion. The relationship of the auxiliary boiler water treatment to the coordinated phosphate curve is given in Figure 220-29-1.

220-29.32

Conductivity is proportional to the concentration of all of the dissolved solids present in the boiler water due to treatment chemicals and contaminants. The conductivity should remain within limits as long as the other test results are within the proper range. High conductivity levels when the other results are within limits indicates contamination from other than a seawater source or a test error.

220-29.33

The chloride level provides an overview of the contamination entering the boiler. Maintaining a chloride of less than 1.0 epm is easily accomplished by maintaining good distillate quality and correcting any in-leakage of seawater or potable water.

220-29.34 MAINTENANCE OF BOILER WATER LIMITS.

The proper chemical levels are maintained by the batch injection of treatment chemicals. In order to determine the amount of chemicals needed, the amount of water requiring treatment and the current boiler water alkalinity and phosphate must be known. The boiler water volume for chemical treatment is given in Table 220-29-3. For vessels that are not listed, the treatment volume can be determined from the boiler weight data given in the instruction manual for the boiler. Determine the weight of water at normal steaming level and divide by 8.33 to find the volume in gallons. Round off to the nearest ten gallons. Notify NSWCCD-SSES if your vessel is not listed or if there is a discrepancy with the data.

220-29.35 ADDITION OF TREATMENT CHEMICALS.

Treatment chemicals are added to the boiler to bring the alkalinity and the phosphate to near the upper limits. The required amount of trisodium and disodium phosphate are weighed to the nearest gram. The chemicals are dissolved in feedwater in the 2-1/2 gallon safety dispensing bottle. The chemicals are sprinkled into the feedwater since disodium phosphate will cake if water is poured onto it. Disodium phosphate will dissolve more easily in warm feedwater; however, do not use water hotter than 50°C (122°F). The safety dispensing bottle shall be marked and used **for boiler treatment chemicals only** . Cap the bottle and spout and shake to dissolve. The chemicals shall be completely dissolved before adding to the treatment tank. The solubility of both trisodium and disodium phosphate is about 850 grams per 1 gallon of water at 50°C (122°F). Wear a face shield when mixing the treatment chemicals and when pouring the chemical solution into the treatment tank. Auxiliary boilers are equipped with a chemical injection system on a bypass of the feedwater line. One treatment system schematic and the general procedures are given in Figure 220-29-2. Other auxiliary boilers have chemical injection systems similar to that used by propulsion boilers. In these cases, general procedures given in Figure 220-22-4 shall be adapted for use, realizing that stop check valves, fill line check valve and topping off line valve may not be installed. When operating the injection system, the tank is overfilled slightly to prevent air from entering the boiler. Overfilling must be minimized to avoid the loss of treatment chemicals.

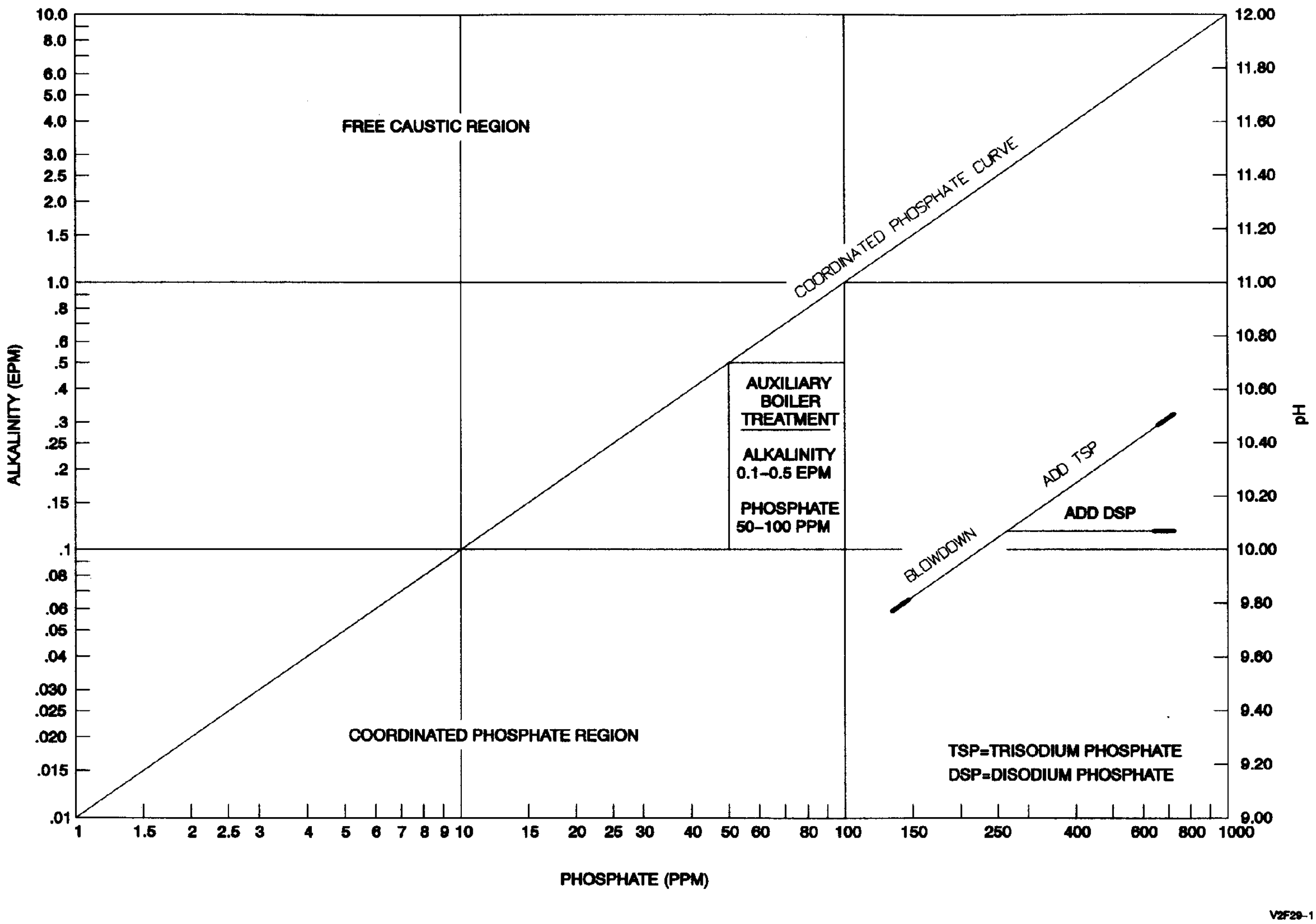


Figure 220-29-1. Coordinated Phosphate Curve (Auxiliary Boilers)

Table 220-29-3. BOILER WATER VOLUME FOR CHEMICAL TREATMENT OF AUXILIARY BOILERS

Vessel	Boiler	Volume (gallons)
AOE 6 thru 10	Combustion Engineering V2M	310
ARD 5	Orr and Sembower	600
ARDM 2	Cleaver-Brooks CB 100-150	690
ARS 8, 38 thru 43	Cyclotherm MC-2500	240
ARS 50 thru 53	Cyclotherm MC-4000	300
AS 18, 19	Combustion Engineering V2M	950

Table 220-29-3. BOILER WATER VOLUME FOR CHEMICAL TREATMENT OF AUXILIARY BOILERS - Continued

Vessel	Boiler	Volume (gallons)
AS 31, 32	Babcock and Wilcox	460
ASR 13, 14, 15, 22	Cyclotherm MC-2500	240
ASR 21	Cyclotherm MC-4000	300
ATF 105, 110, 113	Foster Wheeler	140
ATF 159	Cleaver-Brooks OB-6M	350
ATF 160, ATS 1,2,3	Cyclotherm MC-2500	300
LSD 41 thru 49	Combustion Engineering V2M	310
LST 1179 thru 1198	Combustion Engineering V2M2H	310
MSO 427 thru 492	Cyclotherm MC-800	80
MSO 509, 511	Orr and Sembower	50
YRST 2	York Shipley SPHV-70-2	450

220-29.36 INITIAL TREATMENT.

An auxiliary boiler shall be filled in preparation for steaming with feedwater meeting the requirements of 220-29.23. The boiler should not be filled until just prior to light-off to prevent corrosion due to the oxygenated water. If light-off is postponed for more than 24 hours after the boiler is freshly filled, the boiler shall be dumped and placed under an acceptable layup as prescribed in paragraph 220-29.52. An initial dose of treatment chemicals is added to the boiler when it is freshly filled. A boiler water sample is not obtained from a freshly filled boiler prior to light-off. The procedure for initial treatment is:

WARNING

Wear a face shield when dissolving trisodium phosphate. Concentrated trisodium phosphate solutions are corrosive and cause burns to skin, eyes and body tissues. Affected personnel shall flush skin with cold water. If trisodium phosphate or its solutions enter the eyes, flush with cold water and obtain immediate medical attention.

1. Locate the boiler water volume for chemical treatment, in gallons, from Table 220-29-3.
2. Locate the weights of trisodium phosphate and disodium phosphate, in grams, from Table 220-29-4.
3. Add feedwater at 50°C (122°F) or less to the safety dispensing bottle, do not use more water than the injection tank will hold.
4. Weigh the necessary amount of each chemical and add to the bottle.
5. Cap the bottle and spout, then shake to dissolve.
6. Add the solution to the injection tank and top off with feedwater.
7. Fill the boiler to light-off level with the injection tank aligned to the system.

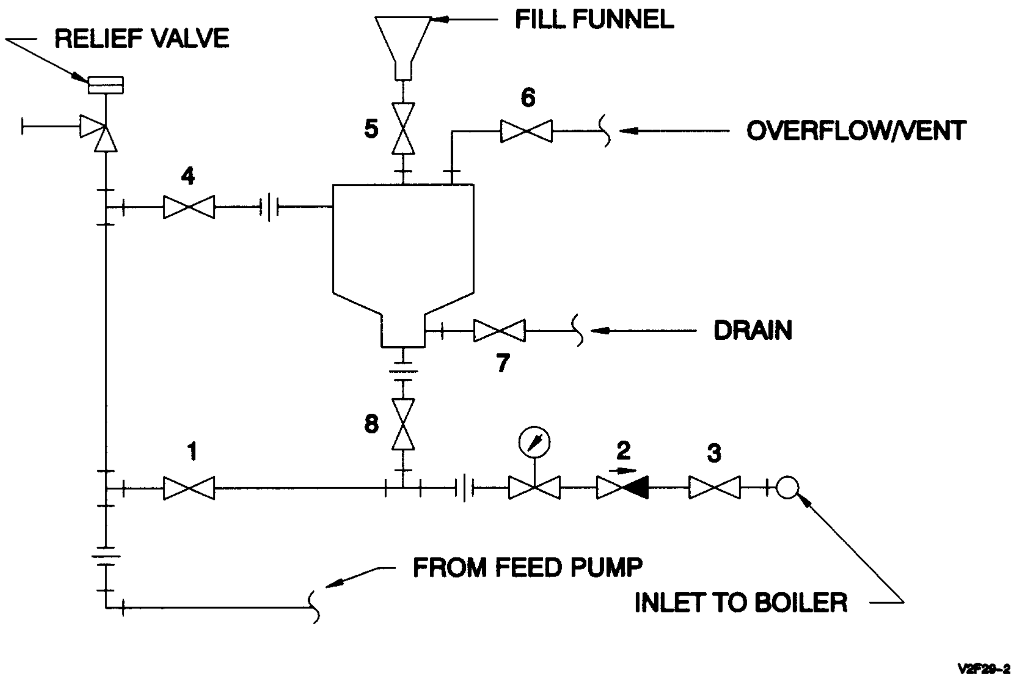
220-29.37 Steaming Auxiliary Boiler.

The boiler water chemistry in a steaming auxiliary boiler shall be maintained within the limits specified in Table 220-29-2. A logic chart for treatment action of a steaming auxiliary boiler is given in Figure 220-29-3. The steaming boiler shall be sampled and tested as follows:

1. Within 1 hour prior to light-off.
2. Within 30 minutes after the boiler has been placed on the line (steam stop valve opened).
3. As often as required to maintain the limits, but at least every 24 hours (maximum of 24 hours between samples).
4. Within 1 hour before commencing blowdowns.
5. 30 to 60 minutes after blowdown.
6. 30 to 60 minutes after chemical treatment.
7. Within 90 minutes prior to securing the boiler.

NOTE

Guidance for sampling prior to and during casualty control drills is contained in paragraph 220-31.48.



Key:

1. Feedwater By–pass Valve
2. Stop Check Valve
3. Feedwater Valve
4. Inlet Valve
5. Funnel Fill Valve
6. Overflow/Vent Valve
7. Drain Valve
8. Outlet Valve

WARNING

Wear a face shield while pouring concentrated chemicals into the injection tank and while topping off.

1. **Ensure that the feedwater injection tank by–pass valve 1 is open and the injection tank inlet and outlet valves 4 and 8 are closed.**
2. **Open the drain valve 7.**
3. **Open the overflow/vent valve 6 and the funnel fill valve 5 to ensure injection tank is empty.**
4. **When the tank is empty close the drain valve 7.**
5. **Add the dissolved chemicals to the tank.**
6. **Top off the injection tank with feedwater through the fill funnel.**
7. **Close the funnel fill valve 5 and the overflow/vent valve 6.**
8. **Open the injection tank inlet and outlet valves 4 and 8.**
9. **Close the feedwater by–pass valve 1 and allow the feedwater to flush the chemicals into the boiler. Record the time the feedwater by–pass valve is closed in the boiler water log. Leave the injection tank aligned to the boiler until after the ACA sample has been taken or until the boiler water level has been raised at least two inches.**
10. **To secure the tank, open the by–pass valve 1 and then close the injection tank inlet and outlet valves 4 and 8.**
11. **Drain the chemical injection tank by first slowly opening the drain valve 7 and then opening the overflow/vent valve 6.**
12. **Close the drain and overflow/vent valves when the tank is empty.**

Figure 220-29-2. Auxiliary Boiler Chemical Injection Procedure

Table 220-29-4. CHEMICAL WEIGHTS NEEDED FOR FRESHLY FILLING AUXILIARY BOILERS (SHIPS WITHOUT PROPULSION BOILERS)

Boiler Water Volume for Chemical Treatment (Gallons)	Weights Required for Initial Treatment	
	TSP (Grams)	DSP (Grams)
50	30	14
80	47	22
140	83	39
240	142	67
300	177	84
310	183	87
450	266	126
460	270	135
600	354	168
690	407	193
950	544	279
TSP = Trisodium Phosphate DSP = Disodium Phosphate		

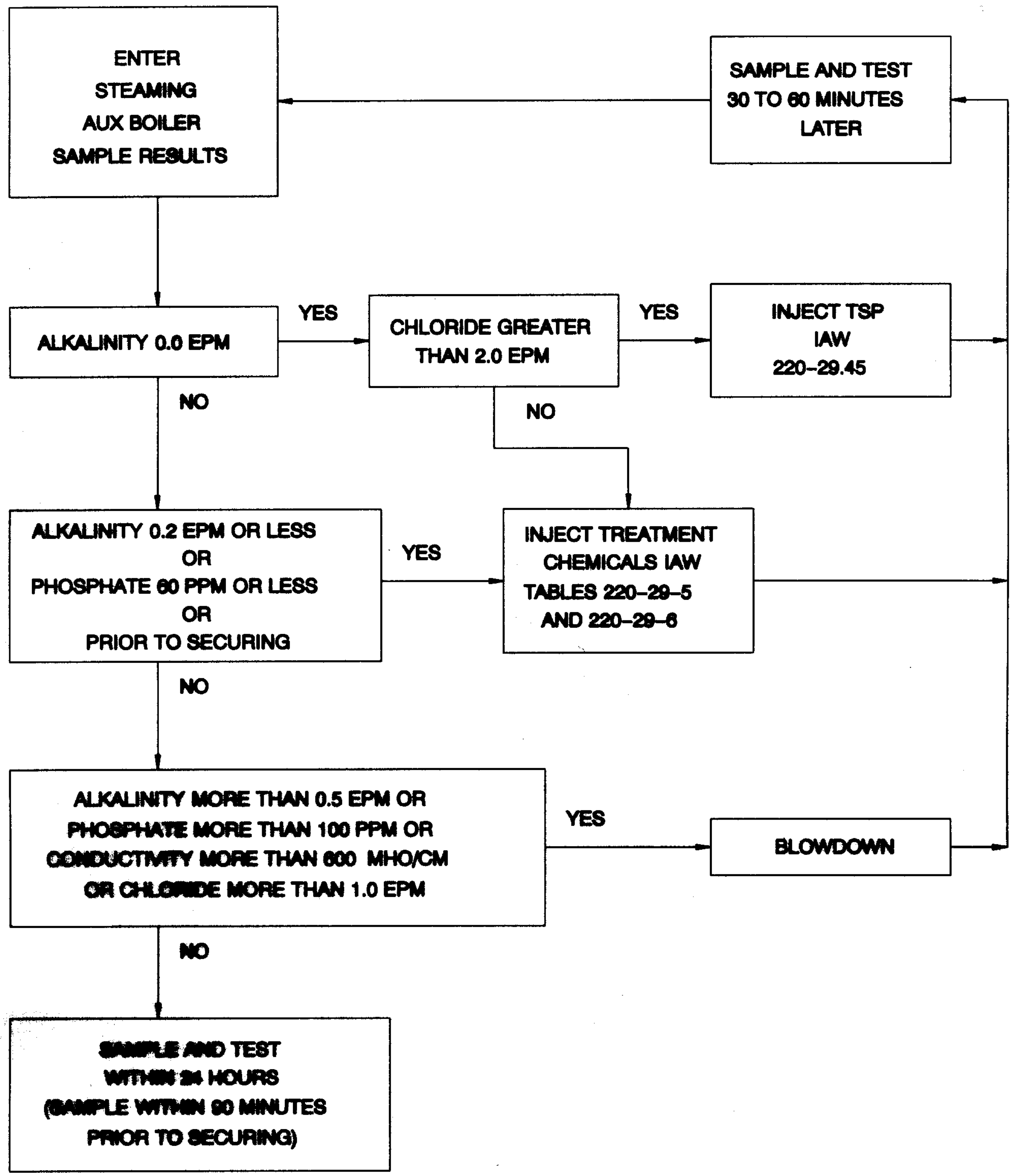


Figure 220-29-3. Logic Chart for Treatment Action of Steaming Auxiliary Boilers

220-29.38 ALKALINITY AND PHOSPHATE.

The addition of trisodium phosphate to raise the alkalinity also raises the phosphate. Therefore, the control of alkalinity and phosphate are linked. The addition of disodium phosphate increases the phosphate only. To determine the amounts of trisodium and disodium phosphate required use the following procedure:

WARNING

Wear a face shield when dissolving trisodium phosphate. Concentrated trisodium phosphate solutions are corrosive and cause burns to skin, eyes and body tissues. Affected personnel shall flush skin with cold water. If trisodium phosphate or its solutions enter the eyes, flush with cold water for 15 minutes and obtain immediate medical attention.

1. Determine the alkalinity and phosphate concentrations in the boiler water from sample results.
2. Locate the boiler water volume for chemical treatment from Table 220-29-3.
3. Locate the boiler water alkalinity from across the top of Table 220-29-5 then read down the column to find the weight of trisodium phosphate required for the appropriate volume. Record this weight in the log.
4. Continue to the last line of the column to find the phosphate correction. This is the amount that the phosphate will increase because of the injection of trisodium phosphate. Record the phosphate correction in the log.
5. Add the phosphate correction caused by trisodium phosphate to the phosphate that was measured in the boiler water. Record the corrected phosphate in the log.
6. Proceed to Table 220-29-6. Locate the corrected phosphate from across the top of the table, then read down the column to find the weight of disodium phosphate required for the appropriate volume. Record this weight in the log.
7. Weigh the chemicals, dissolve them together in the safety dispensing bottle, and inject the solution into the boiler in accordance with paragraph 220-29.35.

220-29.39

When the test results indicate that chemicals are required, the treatment shall be initiated within 60 minutes after the sample was taken. Due to the lower operating pressures, the extent of damage caused by steaming in the free caustic region is much less than for a propulsion boiler. Therefore, blowdown is permissible in the free caustic region to reduce high alkalinity. If required, add treatment chemicals in accordance with normal dosage tables prior to blowdown to prevent alkalinity or phosphate from going below the lower limit.

220-29.40 Conductivity.

The conductivity level is controlled by surface blowdown. The conductivity should be within limits if the alkalinity, phosphate and chloride are maintained within limits.

220-29.41 Chloride.

The chloride level of the boiler water is controlled by surface blowdown. When the feedwater quality is properly maintained, a boiler water chloride of less than 1.0 epm can be achieved without difficulty. If the boiler water chloride is difficult to maintain then the source of the contamination must be located and corrected.

Table 220-29-5. TRISODIUM PHOSPHATE DOSAGE FOR AUXILIARY BOILERS (SHIPS WITHOUT PROPULSION BOILERS)

Boiler Water Volume for Chemical Treatment (Gallons)	Boiler Water Alkalinity								
	0 to 0.025	0.05 to 0.075	0.10 to 0.125	0.15 to 0.175	0.20 to 0.225	0.25 to 0.275	0.30 to 0.325	0.35 to 0.375	0.40 or more
	Grams of TSP required to Raise the Alkalinity to 0.4								
50	30	26	22	18	15	11	7	4	0
80	47	41	35	30	24	18	12	6	0
140	83	72	62	52	41	31	21	10	0
240	142	124	106	89	71	53	35	18	0
300	177	155	133	111	89	66	44	22	0
310	183	160	137	114	92	69	46	23	0
450	266	232	199	166	133	100	67	33	0
460	270	237	203	170	136	102	68	34	0
600	354	310	266	222	177	132	89	44	0
690	408	357	306	255	204	153	102	51	0
950	543	475	407	339	271	199	131	68	0
	Phosphate Correction (ppm)								
	40	35	30	25	20	15	10	5	0
TSP = Trisodium Phosphate									

Table 220-29-6. DISODIUM PHOSPHATE DOSAGE FOR AUXILIARY BOILERS (SHIPS WITHOUT PROPULSION BOILERS)

Boiler Water Volume for Chemical Treatment (Gallons)	Corrected Boiler Water Phosphate, ppm									
	0 to 2.5	5 to 7.5	10 to 12.5	15 to 17.5	20 to 22.5	25 to 27.5	30 to 32.5	35 to 37.5	40 to 42.5	45 to 47.5
	Grams of DSP Required to Raise Phosphate to 90 ppm									
50	25	24	22	21	20	18	17	15	14	13
80	40	38	36	34	31	29	27	25	22	20
140	71	67	63	59	55	51	47	43	39	35
240	121	114	107	101	94	87	81	74	67	60
300	151	143	134	126	118	109	101	92	84	76
310	156	148	139	130	121	113	104	95	87	78
450	226	214	202	189	177	164	151	139	126	113
460	234	221	208	195	182	169	156	142	129	116
600	302	286	269	252	236	218	202	185	168	151
690	348	328	309	290	270	251	232	212	193	174
950	484	457	430	403	375	348	321	294	267	240

Table 220-29-6. DISODIUM PHOSPHATE DOSAGE FOR AUXILIARY BOILERS (SHIPS WITHOUT PROPULSION BOILERS) - Continued

Boiler Water Volume for Chemical Treatment (Gallons)	**Corrected Boiler Water Phosphate, ppm**									
	0 to 2.5	**5 to 7.5**	**10 to 12.5**	**15 to 17.5**	**20 to 22.5**	**25 to 27.5**	**30 to 32.5**	**35 to 37.5**	**40 to 42.5**	**45 to 47.5**
	Grams of DSP Required to Raise Phosphate to 90 ppm									
Boiler Water Volume for Chemical Treatment (Gallons)	**Corrected Boiler Water Phosphate, ppm**									
	50 to 52.5	55 to 57.5	60 to 62.5	65 to 67.5	70 to 72.5	75 to 77.5	80 to 82.5	85 to 87.5	90 or more	
	Grams of DSP Required to Raise Phosphate to 90 ppm									
50	11	10	8	7	6	4	3	1	0	
80	18	16	13	11	9	7	4	2	0	
140	31	27	24	20	16	12	8	4	0	
240	54	47	40	34	27	20	13	7	0	
300	67	59	50	42	34	25	17	8	0	
310	69	61	52	43	35	26	17	9	0	
450	100	88	76	63	50	37	25	13	0	
460	105	92	79	66	53	39	26	13	0	
600	134	118	100	84	67	50	33	17	0	
690	155	135	116	97	77	58	39	19	0	
950	217	190	163	136	109	81	54	27	0	
DSP = Disodium Phosphate										

220-29.42 BOILER WATER CONTAMINATION.

Damage to the boiler or other parts of the plant will occur if the boiler water is seriously contaminated. Refer to paragraph 220-23.8. Criteria for serious, significant damage and moderate contamination conditions are as follows:

Serious Contamination - defined if any of these conditions occur:

1. Alkalinity is less than 0.05 epm.
2. Phosphate less than 10 ppm.
3. Conductivity more than 1500 µmho/cm.
4. Oil visible in samples.

Significant Damage - rapid damage will occur if serious contamination deteriorates to any of these conditions:

1. Alkalinity is zero.
2. Alkalinity greater than 2.0 epm.
3. Phosphate is zero.
4. Conductivity is greater than 2000 µmho/cm.

Moderate Contamination - defined as contamination of boiler water that affects the chemistry, appearance, or odor of the boiler water, but not so severely as to be classed as serious contamination.

220-29.43 ACTION.

Serious contamination of boiler water is a major casualty that demands immediate corrective actions:

1. Inject chemicals to maintain alkalinity and phosphate.
2. Blowdown to reduce contamination.
3. If treatment actions do not return the boiler water to a condition of moderate contamination or normal limits within four hours, secure the boiler unless the Commanding Officer directs continued operation. If operation must be continued, minimize the firing rate.
4. Locate and isolate the source of the contamination.

Securing the boiler will minimize damage, therefore, do not remain steaming simply to treat the boiler. If the boiler is secured prior to the injection of chemicals, add the chemicals immediately after securing. Only one batch injection may be accomplished after securing, since further chemical additions will not be effective due to inadequate circulation. If after this injection the boiler water continues to meet the serious contaminated criterion, the boiler must be dumped. Do not light off another boiler if the feedwater is still contaminated. Serious contamination due to seawater or shore water, followed by chemical additions will generate large amounts of sludge. This must be removed by bottom blowdown as soon as the boiler can be secured. The most effective method of eliminating high levels of contamination is to secure, bottom blow, drain, and flush. Bottom blowdown is required even if the boiler is to be dumped due to contamination. Damage can be controlled by injecting treatment chemicals to restore alkalinity and phosphate, performing blowdowns, minimizing the firing rate or securing and dumping as necessary.

220-29.44 REPORTS.

The cognizant activity (for example, ship, NAVSHIPYD, SUPSHIP) shall provide a detailed message report within 24 hours to the Type Commander with an information copy to the ISIC, NAVSEA and NSWCCD-SSES if any of the following conditions occur:

1. The contamination reaches a condition of significant damage as defined in paragraph 220-29.42 for 8 hours or more.
2. The boiler is steamed under conditions of serious contamination for more than 24 hours.

The information to be included in the report is contained in paragraph 220-23.28.

220-29.45 TREATMENT ACTION DURING SEAWATER CONTAMINATION.

Low levels of seawater contamination can be controlled using the normal dosage tables and blowdown. The source of the contamination must be corrected. High levels of seawater contamination require special treatment. When the chloride level in the boiler is over 2.0 epm and the alkalinity is 0.00 epm, inject only trisodium phosphate in accordance with the following formula:

TSP = (f x chloride)/2

where:

TSP = grams trisodium phosphate, dodecahydrate
f = the amount of trisodium phosphate required for treating the boiler when freshly filling
chloride = boiler water chloride, epm

220-29.46 WATER TREATMENT PRIOR TO SECURING.

Within 90 minutes prior to securing, sample the boiler water. Test the sample and treat the boiler if required. If the boiler is secured prior to obtaining the after chemical addition sample, secure the injection tank after the boiler is secured and use the sample taken one hour prior to blowdown as both the after chemical addition and prior to blowdown sample.

220-29.47 SURFACE BLOWDOWN.

Surface blowdown provides the normal control of boiler water chloride, conductivity, non-detergent lubricating oil and chemical overtreatment. Surface blowdown shall be performed on a steaming boiler as necessary to keep the boiler water within limits. There is no interval specified for performance of surface blowdown since the need for the action is dictated by the chemical test results of the boiler water. If required, treat prior to blowdown to prevent going below limits. A 3 inch blowdown will result in a 5% reduction in all boiler water parameters. When conducting a surface blowdown on a steaming boiler, do not permit the water level to drop below the surface blow take-off or drop out of sight in the boiler water gauge. Maintain a steady feedwater rate and do not change this rate during blowdown. Ensure that the boiler gravity drain hose valve connection is closed and capped during blowdown. The procedure for surface blowdown is:

1. Obtain permission to conduct blowdown.
2. Prepare the blowdown system by first opening the overboard discharge valve(s) and then the guarding valve(s).
3. Establish the water level at 3 inches above the surface blowdown take-off pipe.
4. Wait 4 to 5 minutes and then open the surface blow valve wide. Do not throttle. Maintain continuous observation of the boiler water level during blowdown.
5. Close the surface blow valve quickly when the water level drops to the surface blow take-off pipe.
6. Each 3 inch surface blow will result in a 5 percent reduction.
7. Repeat steps 3 through 5 as required to correct observed conditions.
8. Return water level to normal, close the guarding valve(s) and the overboard discharge valve(s), in that order. Open the drain valve to the bilge to ensure tight seating of the surface blow valve. Close the valve when pressure is relieved. Monel valves require a second securing after a 15-minute cool down to prevent leakage.
9. Note the time of completion of the blowdown in the boiler water log.
10. Sample and test boiler water 30 to 60 minutes after completion of blowdown.

220-29.48 BOTTOM BLOWDOWN.

Bottom blowdown provides the normal control of sludge in the boiler. A bottom blowdown is required weekly (no more than 168 steaming hours between bottom blowdowns). If the boiler water sample contains sediment the bottom blowdown frequency shall be increased to daily (no more than 24 steaming hours between bottom blowdowns). Auxiliary boilers shall also be given a bottom blowdown whenever the boiler is secured for more than 2 hours. Steam blanket pressure is sufficient for blowdown. Ensure that the boiler gravity drain hose valve connection is closed and capped during the blowdown. The procedure for bottom blowdown is:

1. Sample, test, and chemically treat the boiler water within 90 minutes prior to securing.
2. Secure the boiler and let it stand for at least 1 hour.
3. Obtain permission to conduct blowdown.
4. Sample and test the boiler water within 1 hour prior to blowdown.
5. Prepare the blowdown system by opening the overboard discharge valve(s) and the guarding valve(s) in that order.
6. Open each bottom blow valve rapidly to the full open position then immediately close it.
7. On completion of bottom blow, close guarding valve(s) and overboard discharge valve(s) in that order. Open the drain valve to the bilge to ensure tight seating. Close the valve when pressure is relieved. Monel valves require a second shutting after a 15-minute cool down period to prevent leakage.
8. Note the time of completion of the blowdown in the boiler water log.
9. Sample and test the boiler water 30 to 60 minutes after the completion of the blowdown.

220-29.49 PERCENT SURFACE BLOWDOWN.

It is required that the percent blowdown be recorded in the boiler water treatment log. The percent blowdown is determined by using the formula:

$$\% \text{ blowdown} = (100 [C_B - C_A]) / C_B$$

where:
C_B = Conductivity before blowdown
C_A = Conductivity after blowdown

220-29.50 IDLE BOILER WATER TESTING.

The importance of maintaining proper layup during idle boiler periods cannot be overstressed. Proper layup will minimize active oxygen attack and general corrosion of boiler watersides. Within 1 hour prior to bottom blowdown and 30 to 60 minutes after completing bottom blowdown a boiler water sample shall be obtained and tested. No further testing or treatment is required until prior to light-off. Within 1 hour preceding boiler light-off, sample and test the boiler water. This sample is not required for a freshly filled boiler. Add treatment chemicals based on the normal dosage tables only if the alkalinity or phosphate are below the lower limit. If any of the idle boiler samples have a chloride of more than 1.0 epm or a conductivity of more than 600 μmho/cm the boiler shall be dumped and flushed.

220-29.51

An auxiliary boiler under hydrazine/morpholine layup may be lit off without draining and flushing. Inject the initial dosage of treatment chemicals. An auxiliary boiler containing sodium nitrite solution must be drained and flushed prior to being freshly filled and treated.

220-29.52 AUXILIARY BOILER LAYUP

220-29.53

As with main propulsion boilers, the prevention of corrosion in auxiliary boiler watersides, often caused by exposure to the atmosphere, is the major concern when securing. The requirements of paragraphs 220-22.60

through 220-22.77, therefore, also apply to auxiliary boilers. The Oil King shall log the layup status of the auxiliary boiler daily on the boiler water chemistry worksheet/log. Factors such as duration of layup, availability of required equipment, and type of repair work that will be performed should be considered when choosing the type of layup to be used. The applicability of the layup methods to the various types of auxiliary boilers is given in Table 220-29-7.

Table 220-29-7. APPLICABILITY OF WET LAYUP METHODS TO AUXILIARY BOILERS

	Fire-Tube and Watertube Natural Circulation Boilers	Forced-Circulation Boilers
Wet Layup		
Steam blanket	A	N/A
Nitrogen blanket	A	A
Hydrazine/morpholine	A	A
Sodium nitrite	A	A
NOTES: A - Applicable N/A - Not applicable		

220-29.54 DRY METHODS.

Refer to NSTM Chapter 221, Section 5 for dry methods of layup.

220-29.55 WET METHODS.

Wet layup methods include steam blanket, nitrogen blanket, hydrazine/morpholine, and sodium nitrite. These methods are described below.

220-29.56 Steam Blanket.

Steam blanket layup is applicable to all auxiliary boilers except the forced-circulation auxiliary boilers. The procedures, materials, lost layup, time limit, disposal, safety precautions, and preparation for light-off requirements listed in paragraph 220-22.72 apply with the following exceptions:

1. A steam supply from another boiler or shore steam up to a maximum of the boiler operating pressure is required.

2. Do not add feedwater to the secured boiler after the bottom blowdown.

220-29.57 Nitrogen Blanket.

A nitrogen blanket may be used for all types of auxiliary boilers. The procedures, materials, lost layup, time limit, disposal, safety precautions, and preparation for light-off requirements listed in paragraph 220-22.73 apply with the following exceptions:

1. Do not add feedwater to the secured boiler.

2. For forced-circulation auxiliary boilers the nitrogen pressure is applied at the washout inlet connection.

220-29.58 Hydrazine/Morpholine.

This method is applicable to all auxiliary boilers but is to be utilized by industrial activities only. Follow paragraph 220-22.71 for layup procedures and precautions with the exception of the following provisions:

1. Prepare sufficient hydrazine/morpholine treated water to fill the boiler and provide a reservoir, approximately double the steaming volume plus 50 to 100 gallons.
2. Maintain a positive pressure not in excess of the boiler operating pressure.

220-29.59 Sodium Nitrite.

This method is applicable for all auxiliary boilers. The procedures, materials, lost layup, time limit, disposal, safety precautions, and preparation for light-off requirements listed in paragraph 220-22.74 apply with the following exceptions:

1. Prepare sufficient sodium nitrite solution to fill the boiler and provide a reservoir, approximately double the steaming volume plus 50 to 100 gallons. Dissolve 1 pound of sodium nitrite per 100 gallons of feedwater required in a pierside tank or ship's feed tank. Mixing is accomplished by dissolving the sodium nitrite in feed-quality water (10 pounds will dissolve in 2 gallons of water) and then adding the dissolved chemicals to the feedwater in the tank. The tank is then recirculated for 30 minutes to mix the solution.
2. A head tank is the easiest and preferred method of maintaining positive pressure. If a head tank method is used, locate and pipe the head tank above the highest boiler vent.
3. Fill the boiler with sodium nitrite solution and maintain pressure by using a head tank or feed pump.

220-29.60 AUXILIARY BOILER FEEDWATER AND BOILER WATER SAMPLING AND TESTING

220-29.61

Section 24, techniques, and Section 25, safety, pertain to the auxiliary boilers. The procedures for sampling are given in Section 26.

220-29.62 AUXILIARY BOILER FEEDWATER TESTS.

The feedwater tests for auxiliary boilers are the same as those for propulsion boilers. The feedwater tests are:

Feedwater Chloride Test (paragraph 220-26.17)

Feedwater Hardness Test (paragraph 220-26.18)

Salinity Indicator Testing (paragraph 220-26.22)

220-29.63 AUXILIARY BOILER WATER TESTS.

The chloride, conductivity, alkalinity, and phosphate tests for auxiliary boilers are the same as for propulsion boilers. The boiler water tests are:

Boiler Water Conductivity Test (paragraph 220-26.30)

Boiler Water Chloride Test (paragraph 220-26.31)

Boiler Water Alkalinity and Phosphate Test (paragraph 220-26.28)

220-29.64 STANDARDS TESTING.

The standards are tested in the same manner as the applicable boiler water or feedwater sample. The standard tests are run quarterly, when new reagents are prepared, and whenever test results are suspect. Interpret the test results according to paragraphs 220-24.60 through 220-24.64. The procedures are:

Standard	Procedure
Feedwater Hardness	220-26.18
Boiler Water Conductivity	220-26.30
Boiler Water Chloride	220-26.31
Alkalinity	220-26.34

220-29.65 AUXILIARY BOILER RECORD MAINTENANCE

220-29.66

The personnel responsibilities and the general information given in Section 27 applies to the auxiliary boilers. There are six forms available for recording the necessary data used to assist in maintaining proper water conditions in an auxiliary steam plant. The records are:

1. Cover Sheet and Monthly Boiler Data, NAVSEA 9255/6 (6-94).
2. Boiler Water/Feedwater Test and Treatment Chemical Inventory Log, NAVSEA 9255/16 (6-94),(COMMANDING OFFICER DISCRETION).
3. Auxiliary/Waste Heat Feedwater Chemistry Worksheet/Log, NAVSEA 9255/17 (6-94).
4. Auxiliary Boiler Water Chemistry Worksheet/Log, NAVSEA 9255/11 (6-94).
5. Fuel and Water Report, NAVSEA 9255/9 (6-94),(COMMANDING OFFICER DISCRETION).

220-29.67

A complete Steam Plant Water Treatment Log Package shall be compiled each month. This package is retained for two years and shall consist of:

1. The cover sheet and the monthly boiler data.
2. The daily auxiliary/waste heat feedwater chemistry worksheet/logs.
3. The daily auxiliary boiler water chemistry worksheet/logs for each boiler.

220-29.68 COVER SHEET AND MONTHLY BOILER DATA.

This form is maintained as in paragraph 220-27.9 by entering the appropriate data.

220-29.69 BOILER WATER/FEEDWATER TEST AND TREATMENT CHEMICAL INVENTORY LOG.

This log is maintained as in paragraph 220-27.10 by entering the appropriate data.

220-29.70 AUXILIARY/WASTE HEAT FEEDWATER CHEMISTRY WORKSHEET/LOG.

This daily log (Figure 220-29-4, sheets 1 and 2) consists of the following sections:

1. Chemical Test and Salinity/Conductivity Indicator Comparison.
2. Feedwater Tests.
3. Deaerated Feedwater.
4. Remarks.

220-29.71

Initiate a daily log by inserting system number, ship name and hull number, and date. When there is more than one condensate/feedwater system, a separate log is required for each system.

220-29.72 CHEMICAL TESTS AND SALINITY/CONDUCTIVITY INDICATOR COMPARISON SECTION.

This section (Figure 220-29-4, sheet 1) shall be maintained for all feedwater components that are monitored by salinity or conductivity indicators as follows:

AUXILIARY/WASTE HEAT FEEDWATER CHEMISTRY WORKSHEET/LOG

SYSTEM 1 SHIP USS LANDING SHIP DOCK (LSD-94) DATE 5 JUN 94 PAGE 36

CHEMICAL TESTS AND SALINITY/CONDUCTIVITY INDICATOR COMPARISON (REQUIRED DAILY) NOTE: µmho/cm/145=epm

TIME	INDICATOR LOCATION	CHLORIDE ml MERCURIC NITRATEx0.1= epm CHLORIDE		INDICATOR READING		COM-PARISON	HARDNESS ml EDTAx0.2= epm HARDNESS		OIL KING INITIAL
		ml	epm	µmho/cm	epm	SAT/UNSAT	ml	epm	
0226	RESV. FDWTR	.6	.06	5.8	.04	SAT			RE.L
0243	COND. DRNS	.3	.03	2.9	.02	SAT			RE.L
0318	HTR. DRNS	.1	.01		.05	UNSAT	.1	0.02	RE.L
0328	FINAL DISTL.	.3	.03		.04	SAT			RE.L

DEAERATED FEEDWATER

TIME	DFT	CODE	DISSOLVED OXYGEN 15 ppb MAX

LEGEND/TEST CODE

AOL 2 TO 3 HOURS AFTER GENERATOR LIGHT-OFF

RTE WITHIN 24 HOURS

OTH OTHER

FEEDWATER TESTS

TIME	LOCATION	INDICATOR READING µmho/cm or epm	CHLORIDE ml MERCURIC NITRATEx0.1= epm CHLORIDE		HARDNESS ml EDTAx0.2= epm HARDNESS		OIL KING INITIAL
			ml	epm	ml	epm	
0214	AIR EJECTOR	0	.2	.02			RE.L
0255	AIR EJECTOR	.03	.2	.02			RE.L
0702	HTR DRNS	.05	.1	.01			QKC
0836	COND DRNS	12					[illegible]
0845	COND DRNS	13	1.1	.11			[illegible]
0858	COND DRNS	4.35	.3	.03			[illegible]

NAVSEA 9255/17 (6-94)(FRONT) NSN 0116-LF-018-3100

Figure 220-29-4. Auxiliary/Waste Heat Feedwater Chemistry Worksheet/Log (Sheet 1 of 2)

AUXILIARY/WASTE HEAT FEEDWATER CHEMISTRY WORKSHEET/LOG

PAGE 37

TIME	REMARKS:
0214	AIR EJECTOR DRAINS–SALINITY INDICATOR CONSTANTLY READING O, CONTACTED
	IC2 DAILY TO CHECK THE OPERATION OF SALINITY INDICATOR, SAMPLE AND TEST
	AIR EJECTOR DRAINS EVERY 4 HOURS UNTIL INDICATOR IS CORRECTED.
0255	AIR EJECTOR DRAINS– REPAIRED LOOSE WIRE ON SALINITY INDICATOR,
	DISCONTINUED 4 HOUR TESTING.
0318	HEATER DRAINS–CONTACTED IC2 DAILY TO CHECK THE OPERATION OF SALINITY
	INDICATOR, SAMPLE AND TEST HEATER DRAINS EVERY 4 HOURS UNTIL
	INDICATOR IS CORRECTED.
0702	HEATER DRAINS– IC2 LEWIS CHECKED THE OPERATION OF THE SALINITY
	INDICATOR, UNABLE TO CORRECT UNTIL DISTILLER IS SECURED. CONTINUE 4 HOUR
	SAMPLING AND TESTING OF HEATER DRAINS UNTIL INDICATOR IS CORRECTED.
0836	CONDENSATE DRAINS–CONDUCTIVITY ALARM SOUNDED, LOCATE AND ISOLATE
	SOURCE OF CONTAMINATION, SAMPLE AND TEST THE ON-LINE BOILER(S).
0845	CONDENSATE DRAINS–CHEMICALLY TESTED FOR CHLORIDE, LOCATE AND ISOLATE
	CONTAMINATION SOURCE, SAMPLE AND TEST THE ON-LINE BOILER(S).
0846	BYPASSED THE CONDENSATE DRAINS COOLER, TAG OUT AND INSPECT COOLER
	FOR TUBE LEAK.

SHORE STEAM & SHORE SOURCE FEEDWATER SUPPLIER REQUIREMENTS (MAXIMUM)	SHORE STEAM/ CONDENSATE	PROCESSED FEEDWATER
CONDUCTIVITY, µmho/cm	25	2.5
HARDNESS, epm	0.10	–
DISSOLVED SILICA, ppm	0.2	0.2
pH (RANGE)	5.0 TO 9.5	–
TOTAL SUSPENDED SOLIDS, ppm	0.10	–

REQUIREMENTS/LIMITS (MAXIMUM)	SALINITY INDICATOR epm	CONDUCTIVITY µmho/cm	CHLORIDE epm	HARDNESS epm
DISTILLATE	0.065	10.0	0.07	–
DISTILLER AIR EJECTOR DRAINS	0.065	10.0	0.05	–
RESERVE/MAKE-UP/IDLE FEEDWATER	0.10	15.0	0.10	0.10
CONDENSATE/DRAINS/FEEDWATER	0.05	8.0	0.05	0.02
SHORE SOURCE FEEDWATER	–	<40	–	0.10

LCPO INITIAL	LCPO DATE	MPA INITIAL	MPA DATE	REVIEWED: (ENGINEER OFFICER)	DATE
RRA	6 Jun 94	GEF	6 Jun 94	Peter W. S. Butler	6 June 1994

NAVSEA 9255/17 (6-94)(BACK) NSN 0116-LF-018-3200

Figure 220-29-4. Auxiliary/Waste Heat Feedwater Chemistry Worksheet/Log (Sheet 2 of 2)

1. Enter location of salinity or conductivity indicators.
2. Enter time sample was obtained and salinity or conductivity indicator reading was noted. For makeup feed enter the time of indicator reading.
3. Enter buret reading and the calculated chloride test result.
4. Enter salinity indicator reading in epm or conductivity indicator reading in µmho/cm. Convert conductivity results to epm by dividing by 145. Results obtained during comparison tests are analytical results. Any result which is out of limits is circled.
5. Enter satisfactory (SAT) or unsatisfactory (UNSAT) based on the directions in paragraph 220-29.21.
6. When necessary, enter buret reading and hardness test result. Refer to paragraph 220-29.21.
7. Oil King initials and notifies EOOW/EDO of test results.

220-29.73 Feedwater Tests Section.

This section is used for all general feedwater testing. Samples required due to malfunction of salinity or conductivity indicators and samples obtained to locate contamination are entered here. Also entered are salinity or conductivity indicator readings that are out of limits due to contamination. Oil King must be notified when an indicator alarms.

1. Enter time of completion of sampling or reading of salinity or conductivity indicator.
2. Enter location of sample or indicator.
3. Enter the following as required:
   a. Salinity or conductivity indicator reading.
   b. Chloride, buret reading and test result.
   c. Hardness, buret reading and test result.
4. Oil King initials and notifies EOOW/EDO of test result.

220-29.74 Deaerated Feedwater Section.

This section is only used by waste heat boilers with deaerating feed tanks.

220-29.75 Remarks Section.

The remarks section (Figure 220-29-4, sheet 2) shall contain an explanation of each test result which is out of limits, a brief summary of feed system repairs accomplished, the status of repairs or replacement for any malfunctioning salinity or conductivity indicator, and a description of any unusual condition. Ships not using the Reserve/Makeup Feedwater Tests Log enter shore source feedwater results here. All remarks are accompanied by the time as appropriate. Additional pages for remarks may be inserted as necessary.

220-29.76

The Auxiliary Boiler Feedwater Chemistry Worksheet/Log need not be prepared on a daily basis if a plant is in a cold iron status and no testing is required. When no testing is required, enter the inclusive dates on the front of one log and give the reason in the remarks section.

220-29.77

For every day that there is a log, the LCPO shall review and initial the log.

220-29.78 AUXILIARY BOILER WATER CHEMISTRY WORKSHEET/LOG.

The log (Figure 220-29-5, sheet 1) consists of the following sections:

1. Chemical Test Results.
2. Chemical Treatment.
3. Blowdown.
4. Steaming Hour Data.
5. Remarks.

220-29.79

Initiate the daily log for each boiler by entering the boiler number, the ship name, hull number, and the date.

220-29.80

The Chemical Tests Results section shall be maintained as follows:

1. Enter the time on a 24 hour clock basis and the appropriate code for:
   a. Completion of boiler sampling.
   b. Boiler light-off.
   c. Commencement of chemical addition.
   d. Completion of blowdown.
   e. Boiler secured.
   f. Completion of freshly filling the boiler.
   g. Completion of draining the boiler.
   h. Completion of flushing the boiler.
   i. Commencement and completion of full layup conditions.
   j. Other items of interest.
2. Record the test results for each sample.
3. The analyst and the reviewing EOOW initial the log upon completion of the test.

220-29.81

The Chemical Treatment section shall be maintained as follows:

1. Enter the time that the chemical injection is initiated.
2. Enter the grams of trisodium phosphate required.
3. Enter the phosphate correction that will be caused by the addition of trisodium phosphate.
4. Enter the phosphate reading obtained from the sample result.
5. Add the correction to the original phosphate reading and enter the corrected phosphate.
6. Enter the amount of disodium phosphate required.
7. Enter the total amounts of chemicals used for the day.

220-29.82

The Blowdown section shall be maintained as follows:

1. Enter the time of completion of the blowdown operation.
2. Enter the appropriate code for the type of blowdown as given on the back of the log.
3. Enter the conductivity before surface blowdown, enter the conductivity after blowdown and the calculated percent blowdown.

4. Enter the total percent surface blowdown for the day.

220-29.83 Steaming Hours Data Section.

This section (Figure 220-29-5, sheet 2) shall be completed by entering into the **prior hours steamed this month** blocks the **steaming hours** and **steaming hours under moderate** and **serious contamination** from the **hours steamed this month** blocks of the previous day's log. For the first day of the month, enter zeros into the **prior hours steamed this month** blocks. Enter into the **hours steamed today** blocks the current day's **steaming hours** and **steaming hours under moderate** and **serious contamination** . **Steaming hours** are recorded to the nearest 0.1 hours from light-off to securing. **Steaming hours under contamination** start from the sample time when the contamination was detected to the sample time when the boiler water conditions are back within limits or the boiler **is secured** . **Add prior hours steamed this** month to the **hours steamed today** to obtain the **hours steamed this month** . Enter the **hours since last waterside inspection, fireside inspection** and **bottom blowdown** . If more than one log is used for the boiler in any one day, then enter the data on the last log for the day.

220-29.84 Remarks Section.

The remarks section shall describe significant events of the day related to that boiler. Additional pages for remarks shall be inserted as necessary. All remarks are accompanied by the time as appropriate. If a doubt exists as to whether or not an entry should be made in the remarks section, enter it. The following types of events shall be recorded:

1. The setting of boiler safety valves.
2. Hydrostatic tests, including purpose and pressure, and the signature of the witnessing individual.
3. A brief summary of boiler repairs accomplished.
4. Boiler inspection.
5. Explanation of each test result which is out of limits.
6. Description of unusual conditions.
7. The results of tests of the boiler water/feedwater chemicals against standards, except the quarterly tests, are entered on the log for the number 1 boiler. (The results of the quarterly standard tests results are entered on the monthly boiler data.)

220-29.85

The Auxiliary Boiler Water Chemistry Worksheet/Log need not be prepared on a daily basis when the boiler is idle. When no testing is required and no change in boiler condition is occurring, enter the inclusive dates on the front of one log and enter the type of layup applied in the code column, and describe significant events occurring during the idle period. For every day that there is a log the LCPO shall review and initial the log.

220-29.86 FUEL AND WATER REPORT (OPTIONAL AT COMMANDING OFFICER'S DISCRETION).

This form is maintained as in paragraph 220-27.36 by entering the appropriate data.

220-29.87 AUXILIARY BOILER SUPPLY INFORMATION

220-29.88

The general information contained in Section 28 also applies to auxiliary boiler supplies. Specific material recommendations for auxiliary boilers are contained in Table 220-29-8.

220-29.89 FORMS.

The following forms are used to record water conditions in auxiliary boiler systems. They may be obtained through normal supply channels in accordance with NAVSUP Publication 2002.

1. NAVSEA 9255/6 (6-94), NSN 0116-LF-018-2300, Cover Sheet and Monthly Boiler Data.
2. NAVSEA 9255/9 (6-94), NSN 0116-LF-018-2600, Fuel and Water Report.
3. NAVSEA 9255/11 (6-94), NSN 0116-LF-018-2700, Auxiliary Boiler Water Chemistry, Worksheet/Log.
4. NAVSEA 9255/16 (6-94), NSN 0116-LF-018-3100, Boiler Water/Feedwater Test and Treatment Chemical Inventory Log.
5. NAVSEA 9255/17 (6-94), NSN 0116-LF-018-3200, Auxiliary Waste Heat Feedwater Chemistry Worksheet/Log.

AUXILIARY BOILER WATER CHEMISTRY WORKSHEET/LOG

BOILER NO. 1A SHIP USS AUXILIARY (LST-1180) DATE 12 JUN 94 PAGE 60

TIME	CODE	CONDUCTIVITY LIMIT: 800 μmho/cm		ALKALINITY RANGE: 0.1 – 0.5 epm		PHOSPHATE RANGE: 50–100 epm		CHLORIDE LIMIT: 1.0 epm		OIL KING INITIAL	EOOW/ EDO INITIAL
		TEMP. (°C)	CONDUCT- IVITY μmho/cm	ml PHENOL- PHTHALEIN	ml/4 = epm ALKALINITY	ml METHYL PURPLE	mlx25 = ppm PHOSPHATE	ml MERCURIC NITRATE	mlx0.4 = epm CHLORIDE		
0400	RTE	25	250	0.1	0.025	2.0	50	2.8	1.12	JEF	RJK
0420	ADD										
0435	OTH										
0505	ACA/PTB	25	450	1.6	0.400	3.5	87.5	2.9	1.16	JEF	RJK
0525	S										
0610	ABD	25	330	1.3	0.325	2.9	72.5	2.4	0.96	JEF	RJK

CHEMICAL TREATMENT					
TIME	TRISODIUM PHOSPHATE (grams)	TSP CORRECTION FOR PHOSPHATE	CURRENT PHOSPHATE LEVEL	CORRECTED PHOSPHATE	DISODIUM PHOSPHATE (grams)
0420	183	40	50	90	0

BLOWDOWN				
TIME	TYPE	CONDUCTIVITY		% BLOWDOWN
		BEFORE	AFTER	
0525	S	450	330	27

TOTAL TSP INJECTED 193

TOTAL DSP INJECTED 0

TOTAL % SURFACE BLOWDOWN 27

NAVSEA 9255/11 (6-94)(FRONT)

NSN 0116-LF-018-2700

Figure 220-29-5. Auxiliary Boiler Water Chemistry Worksheet/Log (Sheet 1 of 2)

AUXILIARY BOILER WATER CHEMISTRY WORKSHEET/LOG

PAGE 61

TIME	REMARKS:
0400	RTE-SERIOUS SEAWATER CONTAMINATION, INJECT TSP/DSP, 30-60 ACA,
	SEEK AND ISOLATE SOURCE OF CONTAMINATION.
0435	OTH-CONTAMINATION SOURCE EVAPORATOR #1 AIR EJECTOR DRAINS.
0505	ACA/PTB-MODERATE SEAWATER CONTAMINATION, CONDUCT 2-10 PERCENT
	SURFACE BLOWDOWNS, 30-60 ABD.

LEGEND/TEST CODE

AOL WITHIN 30 MIN. AFTER ON LINE
RTE WITHIN 24 HOURS
ADD CHEMICAL ADDITION
ACA 30 TO 60 MIN. AFTER CHEMICAL ADDITION
PTB WITHIN 60 MIN. PRIOR TO BLOWDOWN
ABD 30 TO 60 MIN. AFTER BLOWDOWN
FFT FRESHLY FILLED AND TREATED
LOF LIGHTOFF
ONL ON LINE
SEC SECURED
D BOILER DRAINED
OTH OTHER
PTS WITHIN 90 MIN. PRIOR TO SECURING
PTL PRIOR TO LIGHTOFF

BOILER LAYUP

DRY LAYUP
DES DESICCANT
HTD HEATED AIR

WET LAYUP
STM STEAM (SHIP)
STS STEAM (SHORE)
NIT NITROGEN
DFT HOT DFW FILL
HYD HYDRAZINE
SN SODIUM NITRITE

BLOWDOWNS
S SURFACE
B BOTTOM

	STEAMING HOURS	STEAMING HOURS UNDER CONTAMINATION	
		MODERATE	SERIOUS
PRIOR HOURS STEAMED THIS MONTH	110.3	2.9	0.8
HOURS STEAMED TODAY	24	1.1	1.1
HOURS STEAMED THIS MONTH	134.3	4.0	1.9
HOURS SINCE LAST WATERSIDE INSPECTION	497.3		
HOURS SINCE LAST FIRESIDE INSPECTION	497.3		
HOURS SINCE LAST BOTTOM BLOWDOWN	36.2		

LCPO INITIAL	LCPO DATE	MPA INITIAL	MPA DATE	REVIEWED: (ENGINEER OFFICER)	DATE
SSF	13 Jun 94	MKR	13 Jun 94	Lt M. P. Brown	13 June 1994

NAVSEA 9255/11 (6-94)(BACK)

NSN 0116-LF-018-2700

Figure 220-29-5. Auxiliary Boiler Water Chemistry Worksheet/Log (Sheet 2 of 2)

Table 220-29-8. AUXILIARY BOILER, RECOMMENDED ONBOARD STOCK FOR 6-MONTH DEPLOYMENT (SHIPS WITHOUT PROPULSION BOILERS)

Item	NSN	Unit of Issue	Qty Per Ship
BASIC EQUIPMENT			
Boiler water testing cabinet (complete)	1H 6630-00-372-0839	EA	1
Boiler water conductivity equipment	All items in 220-28.6	N/A	1
Hardness test equipment	All items in 220-28.9	N/A	1
STOCK CHEMICALS			
Chloride indicator capsules	9G 6810-00-753-4907	BT (12)	1
Dimethylglyoxime	9G 6810-01-082-5414	BT (25 g)	1

Table 220-29-8. AUXILIARY BOILER, RECOMMENDED ONBOARD STOCK FOR 6-MONTH DEPLOYMENT (SHIPS WITHOUT PROPULSION BOILERS) - Continued

Item	NSN	Unit of Issue	Qty Per Ship
Hardness buffer	9G 6850-01-390-4335	BT (100 g)	1
Hardness indicator	9G 6850-01-390-4339	BT (100 g)	1
Hardness titrating solution	9G 6810-01-072-1978	GL	1
Isopropyl alcohol (isopropanol, 2-propanol)	9G 6810-00-227-0410	GL	1
Mercuric nitrate	9G 6810-00-281-4163	BT (4 oz)	4
Methyl purple indicator	9G 6810-00-142-9290	BT (12 TT)	1
Nitric acid	9G 6810-00-270-9978	QT	4
Phenolphthalein indicator	9G 6810-00-223-7612	BT (100 g)	1
SPARE EQUIPMENT			
Aspirator bulb assembly (for filling burets)	1H 6640-00-291-1162	EA	2
Balance, triple beam	9G 6670-00-641-7341	EA	1
Bottle, dropper, 60 ml, plastic	9L 6640-01-077-2468	PG (12)	1
Bottle, polyethylene, screw cap, 1 qt	9G 8125-00-819-6085	EA	12
Bottle, reagent, 1 liter (for nitric acid)	9L 6640-00-253-2495	EA	1
Bottle, reagent, 1 liter (for mercuric nitrate)	9L 6640-00-702-2540	EA	1
Bottle, square, 8 oz	9G 8125-00-543-7699	EA	2
Bottle, wash, plastic, 500 ml	9L 6640-00-314-2097	EA	1
Buret assembly, automatic zero, 10 ml, for hardness	1H 6640-01-072-1980	EA	2
Buret, automatic zero, 10 ml, for chloride, alkalinity, and phosphate	9L 6640-00-264-6951	EA	3
Casserole, porcelain, white	9L 6640-00-412-8400	EA	2
Cell, conductivity, dip type, constant of 2.0	1H 6630-00-620-4540	EA	1
Cooler, sample, boiler water	1H 4420-00-376-1545	EA	1
Cylinder, graduated, 100 ml	9L 6640-00-420-0000	EA	3
Dipper, brass	9C 4410-01-077-2467	EA	3
Grease, ground glass joint, silicone	9G 9150-00-965-2408	TU (150 g)	1
Jerrican, plastic, 5 gal	9L 6640-01-083-9756	EA	2
Jug, safety, plastic, 2 1/2 gal	9L 6640-01-083-9755	EA	2
Meter, conductivity Solubridge	9N 6625-00-620-4539	EA	1
Rod, stirring, 7 in long	9L 6640-00-290-0154	EA	6
Scoop, plastic	9Q 7330-01-079-0694	DZ	1
Spatula, nickel-plated steel	9L 6640-00-171-5198	EA	2
Stopper, 2-hole and solid, rubber, size 9	9L 6640-00-935-1108	PG (15)	1
Thermometer, metal, dial type (0 to 100°C)	9G 6685-00-663-8093	EA	2
SAFETY EQUIPMENT			

Table 220-29-8. AUXILIARY BOILER, RECOMMENDED ONBOARD STOCK FOR 6-MONTH DEPLOYMENT (SHIPS WITHOUT PROPULSION BOILERS) - Continued

Item	NSN	Unit of Issue	Qty Per Ship
Apron, rubber	9Q 8415-00-634-5023	EA	2
Face shield	9Q 4240-00-542-2048	EA	2
Gloves, rubber	9D 8415-00-266-8677	PR	6
Gloves, plastic	9D 8415-00-682-6786	PR	100
Goggles	9G 4240-01-364-2169	PR	2
STANDARDS			
Chloride (2.0 epm)	9G 6810-01-129-3762	BT (75 ml)	12
Conductivity (1400 μmho/cm)	9G 6810-00-945-7682	BT (250 ml)	12
Hardness (0.2 epm)	9G 6810-01-125-5234	BT (150 ml)	8
Methyl purple alkalinity (6.0 epm)	9G 6810-01-259-8231	BX(6-100 ml btl)	2
TREATMENT CHEMICALS			
Caustic soda (lye, sodium hydroxide)	9Q 6810-00-270-8177	CO (500 g)	1
Desiccant, 1 lb bag Desiccant, 1/2 lb bag	9G 6850-00-264-6572 9G 6850-00-264-6571	DR (150 bags) DR (300 bags)	1 1
Disodium phosphate anhydrous (sodium phosphate, dibasic, O-S-639)	9G 6810-00-584-4298	DR (25 lb)	2
Humidity indicator card	9G 6685-00-752-8240	CN (125)	1
Sodium Nitrite	9G 6810-00-270-3254	BT (5 lb)	3
Trisodium phosphate dodecahydrate (sodium phosphate, tribasic, dodecahydrate, O-S-642, Type II)	9G 6810-01-082-5415	DR (25 lb)	4

220-29.90 WATER REQUIREMENTS FOR AUXILIARY BOILERS IN SHIPS EQUIPPED WITH CONVENTIONAL STEAM PROPULSION

220-29.91

There are two types of conventional steam propelled ships that have auxiliary boilers: GARCIA, BROOKE, and GLOVER Class frigates and CHARLESTON Class cargo ships. The water chemistry principles and the procedures for sampling and testing are the same as those for the propulsion boilers. The auxiliary boiler water treatment on the frigates is the same as Type B propulsion boiler water treatment. On the CHARLESTON Class ships the treatment procedures differ somewhat from the propulsion boiler water treatment since the auxiliary boiler is a forced circulation boiler. The requirements in the propulsion boiler sections apply to these boilers. The modifications to the treatment requirements due to size and configuration differences are given in this section.

220-29.92 REQUIREMENTS FOR AUXILIARY BOILER FEEDWATER IN SHIPS EQUIPPED WITH CONVENTIONAL STEAM PROPULSION

220-29.93

The feedwater requirements for these boilers are the same as for the propulsion boilers except that the tests for dissolved oxygen and for pH are not required since the DFT and the morpholine treatment system are not used. The feedwater limits are the same whether steaming main or auxiliary. The test results are recorded on the propulsion boiler feedwater records.

NOTE

NSTM Chapter 221 requires that the steam used for propulsion boiler layup be produced from boilers that operate on deaerated feedwater. Therefore the auxiliary boilers cannot provide steam for propulsion boiler layup.

220-29.94 REQUIREMENTS FOR AUXILIARY BOILER WATER ON BROOKE, GARCIA AND GLOVER CLASS FRIGATES

220-29.95

There are two types of auxiliary boilers installed on these ships. An Orr and Sembower boiler is installed on the FF-1040, FF-1041, and FF-1098. The rest have a Cyclotherm MC-4000 boiler. Due to the small boiler volume, the treatment chemicals are weighed in grams instead of ounces. The boiler water volumes for chemical treatment purposes are:

Orr and Sembower	215 gallons
Cyclotherm	300 gallons

220-29.96 INITIAL TREATMENT.

When freshly filling the auxiliary boiler the initial dosage of treatment chemicals is placed in the injection tank and the boiler is filled with the injection tank lined up to the system. Table 220-29-9 lists the weights of trisodium and disodium phosphates needed for initial treatment.

220-29.97 STEAMING BOILER.

The weights of trisodium and disodium phosphate required to maintain the boiler water pH and phosphate are given in Table 220-29-10 and Table 220-29-11. Caustic soda is not used in the auxiliary boiler. The procedure for chemical injection is given in Figure 220-29-2.

Table 220-29-9. CHEMICAL WEIGHTS NEEDED FOR FRESHLY FILLING AUXILIARY BOILERS ON BROOKE, GARCIA, AND GLOVER CLASS SHIPS

Boiler Water Volume for Chemical Treatment (Gallons)	Weights Required for Initial Treatment	
	TSP (Grams)	DSP (Grams)
215	45	60
300	62	84
TSP = Trisodium Phosphate DSP = Disodium Phosphate		

Table 220-29-10. TRISODIUM PHOSPHATE DOSAGE FOR AUXILIARY BOILERS ON BROOKE, GARCIA, AND GLOVER CLASS SHIPS

Boiler Water Volume for Chemical Treatment (Gallons)	**Boiler Water pH**											
	less than 9.00	**9.00 to 9.09**	**9.10 to 9.19**	**9.20 to 9.29**	**9.30 to 9.39**	**9.40 to 9.49**	**9.50 to 9.59**	**9.60 to 9.69**	**9.70 to 9.79**	**9.80 to 9.89**	**9.90 to 9.99**	**10.00 to 10.09**
	Grams of TSP to Raise pH to 10.20											
215	42	41	40	39	37	35	32	29	25	20	13	5
300	58	57	56	54	51	49	45	40	35	27	18	7
	Phosphate Correction (ppm)											
	15	15	12.5	12.5	12.5	12.5	12.5	10	10	7.5	5	2.5
TSP = Trisodium Phosphate												

Table 220-29-11. DISODIUM PHOSPHATE DOSAGE FOR AUXILIARY BOILERS ON BROOKE, GARCIA, AND GLOVER CLASS SHIPS

Boiler Water Volume for Chemical Treatment (Gallons)	**Corrected Boiler Water Phosphate, ppm**							
	0 to 10	**12.5 to 15.0**	**17.5 to 20.0**	**22.5 to 25.0**	**27.5 to 30.0**	**32.5 to 35.0**	**37.5 to 40.0**	**42.5 to 45.0**
	Grams of DSP Required to Raise Phosphate to 50 ppm 50							
215	48	42	36	30	24	18	12	6
300	67	59	50	42	34	25	17	8
DSP = Disodium Phosphate								

220-29.98 CASUALTY CONTROL.

The criteria for defining serious, significant damage and moderate contamination are defined in paragraphs 220-31.95 , and 220-31.96, and 220-31.118 respectively. The casualty control procedures apply to the auxiliary boiler except that caustic soda is not used. Inject the casualty dose of trisodium phosphate whether the boiler is steaming or not. Calculate the casualty dosages in ounces using formulas given, then multiply by 28.35 to obtain the grams of trisodium or disodium phosphate required. Follow the reporting requirements specified in paragraph 220-29.44 for submission of detailed message report while operating the boiler under serious contamination conditions.

220-29.99 IDLE AUXILIARY BOILER WATER.

Refer to paragraph 220-29.52 for layup procedure. Dry layup procedures are given in the auxiliary boiler section of **NSTM Chapter 221** .

220-29.100 RECORD MAINTENANCE.

The same water chemistry records are used for the auxiliary boiler as for the propulsion boiler. The monthly boiler data and the feedwater test results are entered on the propulsion boiler logs. The auxiliary boiler water data is entered on the Boiler Water Chemistry Worksheet/Log, NAVSEA 9255/8. Enter AUXILIARY for the boiler number and change ounces to grams in the chemical treatment section. The boiler water log for the auxiliary boiler is included in the monthly Machinery Plant Water Treatment Log Package.

220-29.101 SUPPLY INFORMATION.

The only additional material required for auxiliary boiler water treatment is:

Balance, triple beam	NSN 9G 6670-00-641-7341

220-29.102 REQUIREMENTS FOR AUXILIARY BOILER WATER ON CHARLESTON CLASS SHIPS

220-29.103

The auxiliary boilers on CHARLESTON Class ships are oil fired, forced circulation, watertube boilers manufactured by Vapor Corporation. The boiler consists of a feedwater pump, the boiler coil and a separator. Feedwater is pumped to the coil where it is heated by the fires. The steam/water mixture then enters the steam separator. The steam leaves the separator by way of the steam outlet. The concentrated boiler water returns to the auxiliary boiler feedwater tank. The boiler is equipped with a coil blowdown and a separator blowdown connection. The boiler operates automatically to maintain the required steam demand.

220-29.104

Ninety percent of the feedwater entering the boiler leaves the separator as steam. Therefore the boiler water in the separator is concentrated about ten times. The treatment level must be low to allow for this concentration effect. The boiler is chemically treated at the auxiliary boiler feedwater tank. Samples are obtained at this tank and tested as boiler water. Ships using coordinated phosphate propulsion boiler treatment shall test the auxiliary boiler feedwater tank for pH, phosphate, conductivity and chloride (Table 220-29-12). Ships using chelant propulsion treatment, test for alkalinity, phosphate, conductivity and chloride (Table 220-29-13).

Table 220-29-12. AUXILIARY BOILER WATER CONTROL LIMITS FOR CHARLESTON CLASS SHIPS USING COPHOS BOILER WATER TREATMENT

pH	8.00 to 10.00
Phosphate	10 to 50 ppm
Conductivity	300 µmho/cm maximum
Chloride	1.0 epm maximum

Table 220-29-13. AUXILIARY BOILER WATER CONTROL LIMITS FOR CHARLESTON CLASS SHIPS USING CHELANT BOILER WATER TREATMENT

Alkalinity	0.025 to 0.100 epm
Phosphate	10 to 50 ppm
Conductivity	300 µmho/cm maximum
Chloride	1.0 epm maximum

NOTE

SHIPALT LKA-1041D provides for the installation of the auxiliary boiler feedwater tank. Ships not having this alteration return the boiler drains to the propulsion boiler feedwater system, therefore, the auxiliary boiler cannot be treated without contaminating the propulsion system. Boilers without the auxiliary boiler feedwater tank shall not be steamed.

220-29.105 Initial Treatment.

Treatment chemicals are added to the auxiliary boiler feedwater tank prior to lighting off the boiler. Dissolve 1 ounce of trisodium phosphate and 3 ounces of disodium phosphate in feedwater in the safety dispensing bottle. Add the dissolved chemicals to the auxiliary boiler feedwater tank and fill the tank with feedwater. Prepare the boiler for light-off. The boiler should not be filled until just prior to light-off to prevent corrosion due to oxygenated water. If light-off is postponed for more than 24 hours after a boiler has been freshly filled, the boiler shall be placed under an acceptable layup in accordance with the auxiliary boiler section of paragraph 220-29.52 or **NSTM Chapter 221** .

220-29.106 Steaming Boiler.

The boiler water conditions at the auxiliary boiler feedwater tank for a steaming boiler shall be maintained within the specified limits. A sample of the boiler water at the auxiliary boiler feedwater tank shall be obtained for a steaming boiler in accordance with the following requirements:

1. Within 1/2 hour after the boiler has been placed on the line (steam stop opened).
2. As often as required to maintain limits, but at least every 8 hours (maximum 8 hours between samples).
3. Within 1 hour before commencing blowdowns (water chemistry related).
4. 30 to 45 minutes after blowdowns are completed (water chemistry related).
5. 30 to 60 minutes after chemical treatment.

NOTE

Guidance for sampling prior to and during casualty control drills is contained in paragraph 220-31.48.

220-29.107 pH and Phosphate.

Trisodium and disodium phosphate are used to maintain the pH/alkalinity and phosphate of the boiler water at the auxiliary boiler feedwater tank within limits. Caustic soda is not used with the auxiliary boiler. Separator blowdown is used to reduce high levels of treatment chemicals. The treatment procedure is as follows:

WARNING

Wear a face shield when dissolving trisodium phosphate. Concentrated trisodium phosphate solutions are corrosive and cause burns to skin, eyes, and body tissues. Affected personnel shall flush skin with cold water. If trisodium phosphate or its solutions enter the eyes, flush with cold water for 15 minutes and obtain immediate medical attention.

1. Determine the pH/alkalinity and phosphate concentrations in the boiler water.
2. Locate the boiler water pH/alkalinity from across the top and locate the boiler water phosphate from the left of Table 220-29-14.
3. The intersection of the pH/alkalinity column and the phosphate row gives the weight of trisodium and disodium phosphate required. Record these weights in the log.
4. Weigh the chemicals, dissolve them in feedwater in the 10 L safety dispensing bottle, and pour this solution into the auxiliary boiler feedwater tank. Record the time the chemicals are added to the tank.

220-29.108 Conductivity.

The auxiliary boiler water conductivity level is controlled by separator blowdown.

220-29.109 Chloride.

The chloride level of the auxiliary boiler water is controlled by separator blowdown.

220-29.110 BLOWDOWN.

Blowdowns are used to control the dissolved and the suspended solids. High levels of dissolved solids from contamination or excess treatment chemicals are reduced by using the separator blowdown valve. The separator blowdown valve is opened for 3 to 5 seconds. This cycle is repeated as required to reduce the high levels. Sludge buildup in the boiler water is controlled by periodic separator blowdowns. The separator blowdown valve is opened for 3 to 5 seconds several times as soon as the boiler is on-line and then once each day. The routine blowdowns are not recorded in the log nor are any samples required before or after the routine blowdowns.

220-29.111 SERIOUS CONTAMINATION/SIGNIFICANT DAMAGE.

Due to the rapid concentration of contaminants in boiler water, the criteria for serious contamination and significant damage are the same. The criteria for serious contamination and significant damage of the auxiliary boiler water on CHARLESTON Class ships are:

1. pH less than 7.00 or alkalinity of 0.000 epm
2. pH greater than 10.50 or alkalinity greater than 0.300 epm
3. Phosphate of 0 ppm
4. Conductivity greater than 600 µmho/cm

220-29.112

If one treatment action does not return the boiler water to within normal or moderate limits then the auxiliary boiler shall be secured. A coil and a separator blowdown are required after the boiler is secured prior to dumping. The boiler and the feedwater tank shall be dumped and flushed. The auxiliary boiler is then ready to be prepared for light-off or to be laid-up. The source of the contamination must be located and corrected. Any test result that is outside normal limits, but does not meet the conditions of serious contamination, is defined as moderate contamination.

Table 220-29-14. TRISODIUM AND DISODIUM PHOSPHATE DOSAGE FOR AUXILIARY BOILERS ON CHARLESTON CLASS SHIPS

Boiler Water pH COPHOS Propulsion Boiler Treatment		**less than 9.00**		**9.00 to 9.99**		**10.00 to 10.50**	
Boiler Water Alkalinity (EPM) Chelant Propulsion Boiler Treatment		**0.025 or less**		**0.050 to 0.100**		**more than 0.100**	
		(Ounces)		**(Ounces)**		**(Ounces)**	
		TSP	**DSP**	**TSP**	**DSP**	**TSP**	**DSP**
Boiler Water Phosphate (ppm)	0 to 10	1	2	0	2.5	0	3.5
	12.5 to 20	1	1.5	0	2	0	2.5
	22.5 to 30	1	0.5	0	0	0	2
	32.5 to 40	1	0	0	0	0	1
	42.5 to 50	1	0	0	0	0	0
	More than 50	1	0	0	0	0	0
TSP = Trisodium Phosphate DSP = Disodium Phosphate							

220-29.113 REPORTS.

The cognizant activity shall provide a detailed message report to the Type Commander with an information copy to ISIC, NAVSEA, and NSWCCD-SSES if any of the following conditions occur:

1. The boiler is steamed under conditions of serious contamination for more than 24 hours.

The information to be included in the report is contained in paragraph 220-23.27 or 220-31.231 for ships using COPHOS propulsion boiler water treatment.

220-29.114 IDLE AUXILIARY BOILER WATER.

A boiler water sample is not obtained on the idle auxiliary boiler. The boiler is given a coil blowdown after securing by opening the coil blowdown valves until the pressure drops to about 25 psig. The separator blowdown valve is then opened for 3 to 5 seconds. The layup procedures are given in paragraph 220-29.52 and the auxiliary boiler section of **NSTM Chapter 221** , Section 5. Prior to light-off, a boiler under wet layup shall be flushed. To flush the boiler, add about 100 gallons of feedwater to the empty auxiliary boiler feedwater tank and pump this water through the coil to the drain tank. Unless the boiler has been recently secured, the boiler will require initial treatment in preparation for light-off; therefore, a sample is not required prior to light-off of the auxiliary boiler.

220-29.115 RECORD MAINTENANCE.

The same water chemistry record sheets are used for the auxiliary boiler on CHARLESTON Class ships as for the propulsion boilers. The monthly boiler data and the feedwater test results are entered on the propulsion boiler logs. The auxiliary boiler water data is entered on either the Boiler Water Chemistry Worksheet/Log, NAVSEA 9255/8 or the Chelant Treatment Boiler Water Chemistry Worksheet/Log, NAVSEA 9255/15, as appropriate. The boiler water log for the auxiliary boiler is included in the monthly Machinery Plant Water Treatment Log Package. The Boiler Water Chemistry Worksheet/Log is modified as follows for use with the auxiliary boiler:

1. Initiate the log by entering auxiliary for the boiler number.
2. Chemical Test Results section: Change the column headings to reflect the auxiliary boiler requirements.
3. Chemical Treatment section: Enter the amount of trisodium and disodium phosphate required. Cross out the columns headed TSP CORRECTION FOR PHOSPHATE, CURRENT PHOSPHATE LEVEL, CURRENT PHOSPHATE and CAUSTIC SODA. Enter the time the chemicals were added to the feedwater tank.
4. Blowdown section: Enter the time of completion of a separator blowdown (SEP) accomplished to reduce chemical levels. Enter the time of completion of the coil blowdown (COIL) after securing the boiler. Do not enter the daily, routine separator blowdowns. Cross out the START column.

220-29.116 SUPPLY INFORMATION.

The supply information given in Section 28 applies. Additional material is not required.

SECTION 30.

WATER REQUIREMENTS FOR WASTE HEAT BOILER SYSTEMS

220-30.1 INTRODUCTION.

This section provides water treatment procedures for the waste heat boilers. The waste heat boiler system consists of three boilers, two condensate/feedwater tanks, and associated pumps and piping. These boilers utilize the waste heat in the exhaust gas from the gas turbine generators to produce steam for the service steam system. There are two types of waste heat boilers:

Manufacturer	Hull Number
Combustion Engineering	DD-997, CG-47 through CG-73
CONSECO	DD-965 through DD-992 and DDG-993 through DDG-996

The components of the two systems are essentially the same but the boiler designs are different. The boiler tubes on the CONSECO are arranged in horizontal coils while the Combustion Engineering (CE) boiler has horizontal straight tubes. The CONSECO boiler coils are stainless steel. The tubes on the CE boiler are chrome-molybdenum alloy steel. The water requirements are the same for all of the waste heat boilers.

220-30.2 WASTE HEAT BOILER STEAM PLANT WATER CHEMISTRY

220-30.3

In general, the principles of water chemistry control given in Section 21 apply to the waste heat boiler system. Additional information specific to waste heat boilers follows.

220-30.4 WASTE HEAT SYSTEM WATER CYCLE.

The overall waste heat system water cycle is a closed system in which feedwater is fed to the boiler, the water is heated to generate steam, the steam is used for ship's services, and is then condensed and returned to the feedwater system. Water for the cycle is obtained from the evaporation of seawater by the distiller. The distillate is added to the feedwater to replace water that is lost from the system due to boiler blowdown, laundry presses, and miscellaneous leaks. The CE boilers have deaerating feedtanks to remove oxygen from the feedwater before the water enters the boiler.

220-30.5 WASTE HEAT BOILER WATER CYCLE.

The waste heat boilers consist of a steam drum/separator, a circulating pump, an inlet and an outlet header, and the generating tubes. Feedwater is supplied to the boiler through the feedwater control valve. The boiler water is circulated from the steam drum/separator to the inlet header by a circulating pump. The water then enters the tubes where it is heated by the exhaust gases to generate steam. The steam/water mixture leaves the tubes via an outlet header to the separator where the steam/water is separated by centrifugal action. The water drops to the lower portion of the drum/separator and the steam exits the top of the boiler to the main steam line.

220-30.6

The amount of steam produced by the waste heat boilers is dependent on the generator load rather than the steam demand. When more steam is produced than is required, the excess steam is condensed and cooled by a control condenser. The drains from the main steam system are condensed and cooled by a condensate cooler. The condensate is then returned to the feedwater tank.

220-30.7 FEEDWATER CONTAMINANTS.

Maintaining good quality feedwater is essential to effective control of the water chemistry. The water conditions must be controlled within the allowable limits to prevent waterside corrosion, scale formation, and carryover.

220-30.8

In a properly operating waste heat boiler system the distillate contains the highest level of contaminants. Therefore, the makeup rate will determine the amount of contaminant that enters the boiler. High makeup rates will cause the boiler water chloride and conductivity to increase, and lead to a higher usage of treatment chemicals. This will cause greater sludge formation and an increase in the deposits on the watersides. The makeup rate shall be maintained at a minimum by correcting all system leaks. On a properly maintained system the makeup rate should be less than 900 gallons per day.

220-30.9 SEAWATER.

Seawater is the most common contaminant found in marine boiler systems. The usual source of intermittent seawater contamination is the distillers, especially during light-off of the distiller. The distiller air ejector drains and the feedwater heater drains should be diverted to the bilge during light-off until the salinity/conductivity indicators read within limits. The drains must be dumped whenever the salinity/conductivity indicator alarms. The evaporator watch shall notify the oil king when contamination occurs so that the boiler water may be tested. Contamination from the distiller air ejector drains can cause a rapid, large increase in the boiler water chloride since the contamination is brine (concentrated seawater). A small condenser leak will cause a continual, low level increase in the boiler water chloride. A small leak can be difficult to locate. Methods of testing for tube leaks are given in **NSTM Chapter 254, Condensers, Heat Exchangers, and Air Ejectors.** The following summarizes the sources, detection methods, effects and corrective actions for seawater contamination:

1. Source
   a. Distillate; dump valve malfunctioning or bypassed
   b. Distiller air ejector or feedwater heater drains; leak or brine carryover to the air ejector
   c. Condensate cooler; tube leak
   d. Control condenser; tube leak
2. Detection
   a. Salinity/conductivity indicators
   b. Chemical chloride test
3. Effect on boiler water
   a. Alkalinity decreases
   b. Phosphate decreases
   c. Conductivity increases
   d. Chloride increases
4. Corrective action
   a. Find, isolate, and correct source of contamination.
   b. Sample and test boiler water as necessary to keep alkalinity and phosphate within limits.
   c. Blowdown to remove contamination.
   d. The most effective method to remove high levels of contamination from the boiler is to secure, cool, dump and flush.

220-30.10 SHORE WATER.

Shore water contamination is caused by either shore potable water entering the feedwater system or by the use of contaminated shore source feedwater or steam. The salinity/conductivity indicator readings will increase when shore water contamination occurs. The feedwater chemical chloride test result will be lower than the chloride level indicated by the salinity/conductivity indicators. The effects of shore water contamination will stop after a few days at sea as the shore source water is replaced with distillate. The usual source of shore potable water contamination is through a leak in a hot water heater steam coil. The source of a small leak can be very difficult to find. Monitoring the salinity/conductivity indicators and the condensate hardness while each heater is secured for 30 minutes, and then placed back in service will help indicate the source. The following summarizes the sources, detection methods, effects and corrective actions for shore water contamination:

1. Source
   a. Hot water heaters; leaking steam coil
   b. Shore source feedwater; contaminated
   c. Shore steam; contaminated
2. Detection
   a. Condensate cooler salinity indicator
   b. Feedwater hardness test
3. Effect on boiler water
   a. Alkalinity will increase
   b. Phosphate will decrease
   c. Conductivity will usually increase
   d. Chloride will usually increase
4. Corrective action
   a. Find, isolate, and correct source of contamination.
   b. Sample and test boiler water as necessary to keep alkalinity and phosphate within limits.
   c. Blowdown to remove contamination.
   d. The most effective method to remove high levels of contamination from the boiler is to secure, cool, dump and flush.

220-30.11 OIL.

The steam can become contaminated with oil if a leak occurs at the fuel or lubricating oil heaters. Oil entering the feed system will coat the salinity/conductivity cell electrodes causing erroneous low readings. The cells must be cleaned in alcohol to remove the oil film until the contamination is corrected. The following summarizes the sources, detection methods, effects and corrective actions for oil contamination:

1. Source
   a. Fuel oil heater; leak
   b. Lubricating oil heater; leak
2. Detection
   a. Oily condensate in inspection tank
   b. Oil in feedwater or the boiler water sight glass
   c. Oil in feedwater or the boiler water samples
3. Effect on boiler water chemistry
   a. No effect on the alkalinity, phosphate, conductivity, or chloride

b. May induce carryover

4. Corrective action
   a. Find, isolate, and correct source of contamination.
   b. Surface blow the CE boiler to remove contamination. Treat as necessary to keep alkalinity and phosphate within limits if boiler is steaming.
   c. Securing, dumping and flushing may remove oil contamination.
   d. If contamination is severe then clean boiler with an alkaline boil out in accordance with **NSTM Chapter 221, Boilers.**

220-30.12 DISSOLVED OXYGEN.

The presence of dissolved oxygen in the feedwater entering the boiler will cause corrosion of the non-stainless steel coils. On the CE boiler a deaerating feedwater tank is installed to reduce the oxygen level so that the corrosion rate is minimized. A DFT is not required with the stainless steel coils. The feedwater dissolved oxygen test is used to detect a malfunctioning DFT. The cause of a malfunction should be found and corrected as soon as possible. Possible causes are:

1. Improper operation of the DFT spray valves or steam atomizing valve.
2. Inadequate venting of the DFT.
3. Excessive water level in the DFT, flooding the steam atomizing valve.
4. Fluctuating steam supply pressure as a result of a malfunction of the steam control valve.

220-30.13 OTHER CONTAMINANTS.

Other contamination sources are:

1. Metal corrosion products and suspended solids. Corrosion products from the feedwater system are washed to the boiler. To some extent erosion of the feedwater system metal surfaces also contributes suspended matter to the boiler water. These particles contribute to the formation of sludge in the boiler water. This will be most noticeable after long idle periods and will be indicated by discoloration of the boiler water. Extra blowdowns or securing and dumping are required to remove the sediment from the boiler.
2. Preservatives. Metal preservative coatings are used to protect metal surfaces after manufacture. The preservative is usually removed prior to installation aboard ship. Contamination from preservatives is usually found only in new ships where the preservative has not been properly removed. Preservative contamination can also occur when piping is replaced without removing the preservative from the new component. Preservative that is washed to the boiler will bake onto the boiler tubes. Preservative contamination is removed by an alkaline boil out in accordance with **NSTM Chapter 221** .
3. Dirt and Debris. Whenever the waste heat boiler system is open for repair or maintenance, care must be taken to prevent dirt from entering the system. Dirt and debris that has entered the system will contribute to the suspended matter in the boiler water and may increase the waterside deposits. The effects will be seen when the generator is first lit off, the boiler water sample will be dark and may be difficult to test. The boiler water chemistry may be affected. Extra blowdowns or securing and dumping will be required to remove the sediment.

220-30.14 REQUIREMENTS FOR WASTE HEAT BOILER FEEDWATER

220-30.15

The feedwater requirements for waste heat boilers are based on the actual values attainable for a properly operated system. The feedwater limits are the maximum allowed. Whenever the feedwater test results exceed the limits, either by salinity/conductivity indicator or by chemical tests, the source of the contamination must be located and corrective action taken. The values should be maintained at the lowest levels for routine control of the boiler water. The limits are summarized in Table 220-30-1.

220-30.16 Salinity/Conductivity Indicators.

All installed feedwater salinity/conductivity indicating devices shall be monitored for any signs of contamination. The salinity/conductivity indicators give the first warning of contamination and corrective action is taken as soon as the contamination is detected. Salinity/conductivity indicator alarms and dump valves shall be set as close to the limit as the installed hardware permits. Replacement or modification of the hardware is not authorized or required by this chapter.

220-30.17

Salinity indicators and conductivity indicators both measure the conductivity of the water. Salinity indicators are labeled to read in epm of chloride based on the conductivity of seawater. If contamination from other than a seawater source is present the salinity/conductivity indicators will read higher than the chemical chloride test.

220-30.18

Continuous monitoring of either boiler feedwater or all condensate contamination sources by salinity or conductivity indicators is required to ensure maintenance of boiler water quality. If waste heat boiler feedwater or condensate quality is not continuously monitored by salinity or conductivity indicators installed in either all condensate streams or in the feedwater piping, boiler water shall be sampled and tested every four hours. When individual salinity/conductivity indicators are not operational, except distillate or reserve feedwater, either sample the affected feedwater and chemically test for chloride every four hours or sample and test boiler water every four hours. If distillate cannot be continuously monitored, send distillate to an isolated tank and test for chloride 30 minutes prior to placing on makeup.

220-30.19 CHEMICAL TESTS AND SALINITY/CONDUCTIVITY INDICATOR COMPARISON.

The salinity/conductivity indicators that monitor condensate (excluding air ejector drains), feedwater, distillate, and distiller drains shall be checked daily when in use to ensure satisfactory operation of the indicator. Ships equipped with conductivity indicators which read out in µmho/cm are required to convert the µmho/cm to epm chloride prior to making the comparison. To convert a conductivity indicator reading in µmho/cm to epm chloride divide the conductivity reading by 145.

Table 220-30-1 WASTE HEAT BOILER FEEDWATER, REQUIREMENTS SUMMARY

Source	Maximum Limit			
	Conductivity Indicator µmho/cm	**Salinity Indicator epm**	**Chemical Chloride epm**	**Chemical Hardness epm**
Distillate	10.0	0.065	0.07	----

Table 220-30-1 WASTE HEAT BOILER FEEDWATER, REQUIREMENTS

SUMMARY - Continued

	Maximum Limit			
Source	**Conductivity Indicator µmho/cm**	**Salinity Indicator epm**	**Chemical Chloride epm**	**Chemical Hardness epm**
Distiller Air Ejector Drains	10.0	0.065	0.05	----
Idle Feedwater Tank	----	-----	0.10	0.10
Feedwater, Condensate, Drains	8.0	0.050	0.05	0.02
				Dissolved Oxygen ppb
Deaerated Feedwater				15

Source	**Test Frequency**
All distillate, condensate, and feedwater monitored by salinity indicators.	Perform daily comparison test on all salinity indicators that can be sampled (except distiller air ejector drains).
	Monitor indicators whenever system component is operating.
	When indicator is malfunctioning, test the water that is monitored by the affected indicator for chloride every 4 hours or test boiler water every 4 hours.
Distiller air ejector drains	Test for chloride daily.
	When indicator malfunctions or indicates an out of limits condition, test for chloride every 4 hours. Drains may be used based on chemical chloride test.
Idle feedwater tanks	Test feedwater tanks for chloride and hardness within 24 hours prior to light off.
	Test feedwater tanks after filling with distillate or shore source feedwater.
Deaerated feedwater	Test for dissolved oxygen 2-3 hours after boiler is steaming and then daily.

NOTE

Salinity indicator alarm and dump valves shall be set as close to the above limits as installed hardware permits. Replacement or modification of installed hardware is not authorized or required by this chapter. Updating of these systems is only approved by ship alteration as authorized by the Type Commander and NSWCCD.

This check shall be made by comparing the chemical test result for feedwater chloride to the salinity/conductivity indicator reading (measured in or converted to epm chloride). Sampling of the water and reading of the salinity/conductivity indicator is accomplished concurrently:

1. If the difference between the chemical test result and the indicator reading is 0±0.02, the comparison is satisfactory.

2. If the chemical test result is higher than the indicator reading by more than 0.02, the comparison is unsatisfactory and the indicator must be checked for malfunction (paragraph 220-24.70).

3. If the chemical test result is lower than the indicator reading by more than 0.02, check the water for hardness (excluding distillate)* . If the hardness is 0.02 epm or less, check the indicator for malfunction. If hardness is more than 0.02 epm, the indicator is functioning satisfactorily.

*The comparison test for distillate is based only on chemical chloride because the hardness test may give false high results. If the chemical chloride test result is lower than the indicator reading by more than 0.02 epm, check the indicator for malfunction.

4. An indicator that constantly reads zero shall be checked for malfunction.

NOTE

Salinity or conductivity indicator readings higher than chemical chloride may also occur due to the presence of dissolved gases when operating in coastal, river, bay or port waters, or due to volatile chemicals following hydrazine layup or use of shore steam. If high salinity/conductivity indicator readings for distillate or distiller air ejector drains continue in the absence of high chemical chloride when operating in coastal, river, bay or port waters for extended periods, the following applies:

a. Test for chemical chloride every four hours.
b. Use of the water is based on chemical chloride.
c. Salinity/conductivity indicator limit/alarm set point/dump set point may be set to a value just above the distillate/air ejector drain salinity/conductivity. Record time/alarm set point in Remarks section of Feedwater Log.
d. Reset salinity/conductivity indicator limit/alarm set point/dump set point to normal values when indicator readings return to normal limits. Record in the remarks section of the feedwater log.

220-30.20

The comparison test is accomplished by sampling at a location near the cell. Many of the waste heat boiler systems do not have a sample test connection at either the condensate cooler or the control condenser. If this is the case, then these cells shall be compared to a feedwater tank sample. Do not perform the comparison using a feedwater tank sample within 1 hour of adding distillate to the feedtank. During light-off of the waste heat boilers, the water level in the steam drum/separator will usually increase until boiler water overflows into the steam/condensate system. Since boiler water contains treatment chemicals which contribute to the conductivity of the water, the indicators will read higher than the chemical chloride test. This contamination may also occur when the boiler is secured. Therefore, do not perform the comparison tests within one hour after lighting off or securing. Some of the waste heat boilers have a problem with excessive carryover. The salinity/conductivity indicators will read higher than the chemical test if carryover is excessive. Refer to paragraph 220-30.69.

220-30.21 DISTILLATE.

Distillate is continuously monitored by a salinity or conductivity indicator at the discharge of the distilling unit. The limit is 0.065 epm chloride by salinity indicator or 10 µmho/cm by the conductivity indicator. The indicator controls a solenoid valve which dumps the distillate to the bilge if the limit is exceeded. The daily comparison test will assure that the cell is reading correctly. The limits by chemical test for distillate discharging to feed are 0.07 epm chloride. Distillate not meeting the requirements shall not be used as feedwater.

220-30.22 IDLE FEEDWATER TANKS.

All feedwater tanks shall be sampled and tested for chloride and hardness within 24 hours prior to light off of a cold plant. The limits by chemical test are 0.10 epm chloride and 0.10 epm hardness. If distillate or shore source feedwater is required prior to light off, the tank samples shall be obtained after the tanks have been filled. Water exceeding these limits shall be dumped.

220-30.23 FEEDWATER.

Ships having the conductivity indicator system shall monitor the feedwater entering the boiler for any sign of contamination. The limit is 0.05 epm by salinity indicator or 8 µmho by conductivity indicator. The daily comparison test will assure that the cell is operating properly. The limits by chemical test are 0.05 epm chloride and 0.02 epm hardness. The feedwater may be above the limits for about 1 hour after a tank is placed on suction due to higher limit for feedwater in an idle tank.

220-30.24 CONDENSATE AND DRAINS.

Whenever the feedwater system is operating the salinity/conductivity indicator for the applicable control condenser, condensate cooler, or distiller condensate shall be monitored for any sign of contamination. The limit is 0.05 epm by salinity indicator or 8 µmho/cm by conductivity indicator. The daily comparison test will assure that the cell is operating properly. The limits by chemical test are 0.05 epm chloride and 0.02 epm hardness.

220-30.25 DISTILLER AIR EJECTOR DRAINS.

The chloride limit by chemical test for distiller air ejector drains is 0.05 epm. Carbon dioxide gas removed from the distilling unit can dissolve in the air ejector drains causing the salinity or conductivity readings to be higher than the actual chloride content. Therefore, the limit by salinity indicator is 0.065 epm or by conductivity indicator is 10 µmho/cm. The daily salinity/conductivity comparison test is not required. The high bicarbonate level can also interfere with the hardness test giving false high results. The hardness test is not accomplished on distiller air ejector drains. A chemical chloride test of distiller air ejector drains is required daily and every four hours if the salinity/conductivity indicator malfunctions or indicates an out of limits condition. Use of distiller air ejector drains is based on the chemical chloride test.

220-30.26 DEAERATED FEEDWATER.

The dissolved oxygen content shall not exceed 15 ppb. The deaerated feedwater is tested for dissolved oxygen 2 to 3 hours after a boiler is steaming and then daily (no more than 24 hours between samples). This requirement applies to the CE boilers and those non-stainless steel CONSECO boilers with a DFT installed.

220-30.27 SHORE STEAM AND SHORE SOURCE FEEDWATER.

Steam and feedwater from a shore source shall meet the requirements of paragraphs 220-22.18 through 220-22.22. Documentation certifying that the water meets these requirements shall be obtained from the supplying facility or contractor. Ship's force shall sample and test each shipment of shore source feedwater prior to acceptance and at each tank that receives water for compliance with the following requirements:

Test	Requirement
Hardness	0.10 epm
Conductivity	less than 40 µmho/cm*

*The lowest reading on the shipboard conductivity meter is 40 µmho/cm.

220-30.28 REQUIREMENTS FOR WASTE HEAT BOILER WATER

220-30.29

The chemical treatment used in the waste heat boilers is designed to provide alkalinity and phosphate within specified limits. The treatment is a coordinated phosphate treatment which prevents acid corrosion, caustic corrosion, scale formation and minimized carryover. The same treatment is used in all waste heat boilers. The waste heat boilers limits are given in Table 220-30-2.

Table 220-30-2 WASTE HEAT BOILER WATER CONTROL LIMITS

Conductivity	500 μmho/cm maximum
Alkalinity	0.05 to 0.25 epm
Phosphate	25 to 75 ppm
Chloride	1.0 epm maximum

220-30.30

Trisodium phosphate and disodium phosphate are the chemicals used to treat the waste heat boiler water. Trisodium phosphate provides alkalinity and some of the phosphate. The disodium phosphate provides additional phosphate while contributing little to the alkalinity. Maintaining alkaline boiler water prevents acid corrosion and is necessary for the reaction between the phosphate and the scale formers. The additional phosphate prevents the formation of free caustic in the boiler water which could lead to caustic corrosion. The relationship of the waste heat boiler water treatment to the coordinated phosphate curve is shown in Figure 220-30-1.

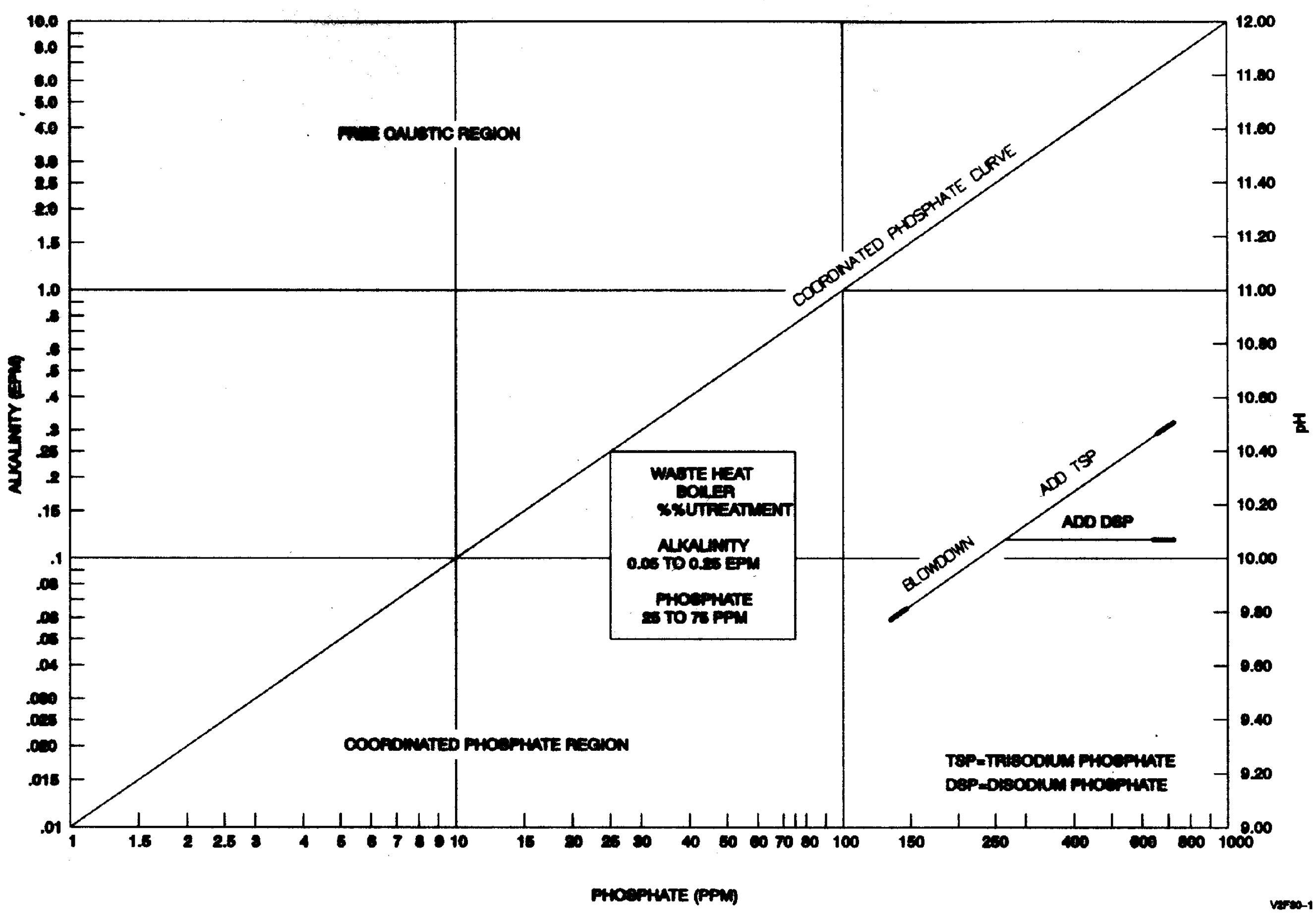


Figure 220-30-1 Coordinated Phosphate Curve (Waste Heat Boilers)

220-30.31

The conductivity is proportional to the concentration of all of the dissolved solids present in the boiler water due to treatment chemicals and contaminants. The conductivity should remain within limits as long as the other test results are within the proper range.

220-30.32

The chloride level provides an overview of the contamination entering the boiler. Maintaining a chloride level of less than 1.0 epm is easily accomplished by maintaining good quality distillate and correcting any in-leakage of seawater or potable water.

220-30.33 MAINTENANCE OF THE BOILER WATER LIMITS.

Normal control of the chemical levels is by the continuous treatment system. The batch treatment system is used to provide an initial treatment and whenever the chemical levels are near or below the lower limits. The batch treatment system will be required when the continuous system is not operating. The boiler water volumes for chemical treatment purposes are:

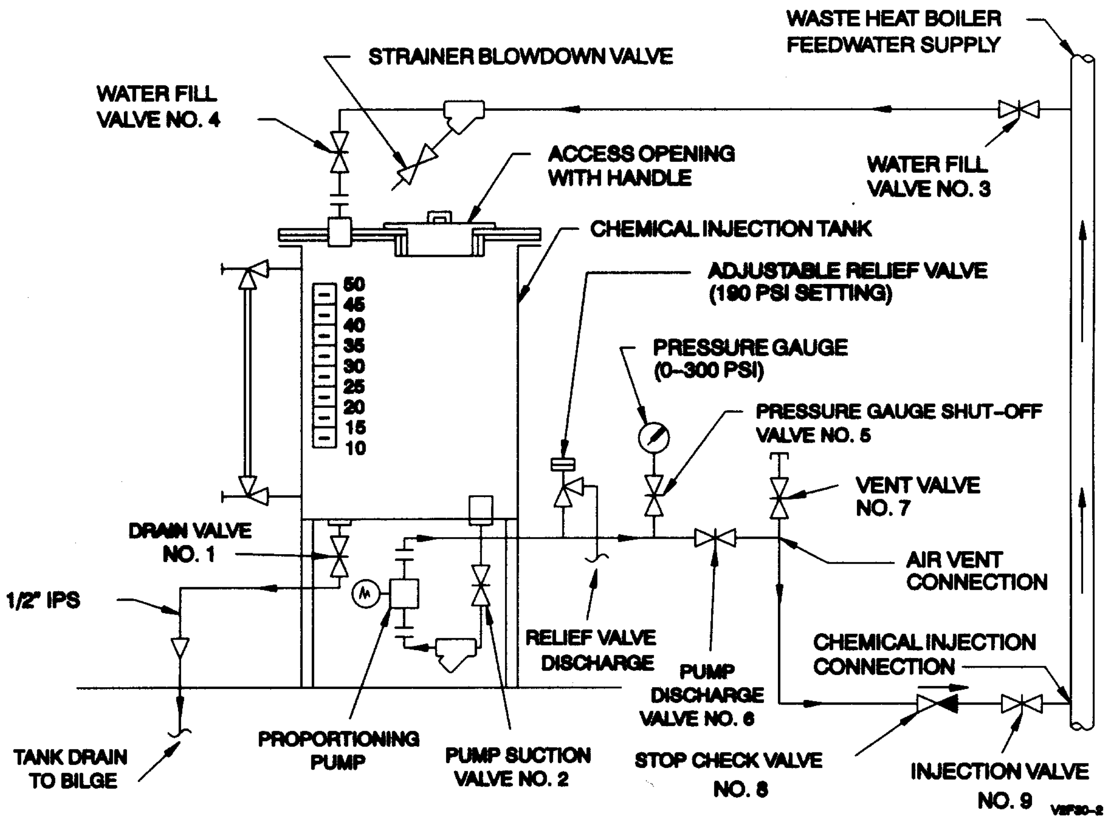
CE	100 gallons	DD-997, CG-47 through CG-73
CONSECO	200 gallons	DD-965 through DD-992, and DDG-993 through DDG-996

220-30.34 HANDLING OF TREATMENT CHEMICALS.

The required amount of trisodium and disodium phosphate are weighed to the nearest gram. The chemicals are dissolved in feedwater in the 2-1/2-gallon safety dispensing bottle. The chemicals are sprinkled into the feedwater since disodium phosphate will cake if water is poured onto it. Disodium phosphate will dissolve more easily in warm feedwater; however, do not use water hotter than 50°C (122°F). The safety dispensing bottle is to be marked and used **FOR BOILER WATER TREATMENT CHEMICALS ONLY** . The chemicals shall be completely dissolved before adding to the treatment tank. Wear a face shield when mixing the treatment chemicals and when pouring the chemical solution into the treatment tank.

220-30.35 CONTINUOUS TREATMENT TANK SOLUTION PREPARATION.

See Figure 220-30-2 and Table 220-30-3 to prepare the continuous treatment tank solution.



Key:

1. Drain Valve
2. Pump Suction Valve
3. Water Fill Valve
4. Water Fill Valve
5. Pressure Gauge Shutoff Valve
6. Pump Discharge Valve
7. Vent Valve
8. Stop Check Valve
9. Injection Valve

FILLING THE INJECTION TANK

WARNING

Wear a face shield when handling trisodium phosphate or its solutions.

1. Find the weights of trisodium and disodium phosphate required for filling the continuous injection tank from Table 220-30-3.

2. Weigh the chemicals, dissolve them in feedwater in the safety dispensing bottle.

3. The injection pump must be secured during the filling procedure.

4. Close pump suction valve 2 and ensure that drain valve 1 is closed.

5. Remove the access cover, pour the dissolved chemicals into the continuous injection tank, and replace the access cover.

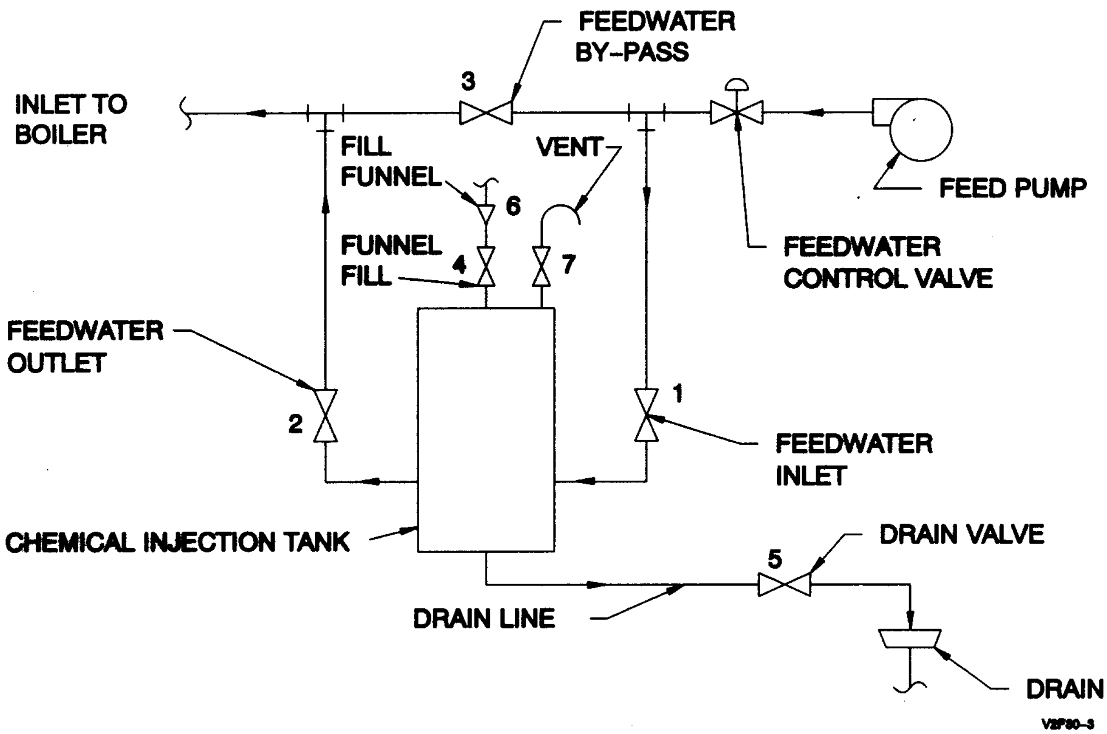
6. Fill the tank to the 50 gallon mark using the water fill line valves 3 and 4. The feedwater pump must be operating.

7. Open pump suction valve 2. Return the pump to operation if the boiler is steaming.

Figure 220-30-2 Waste Heat Boiler Continuous Injection System

220-30.36 INITIAL TREATMENT.

A waste heat boiler shall be filled, in preparation for steaming, with feedwater meeting the requirements of paragraph 220-30.22. An initial dosage of treatment chemicals shall be placed in the batch injection tank and the boiler filled through the injection tank, Figure 220-30-3. The amount of trisodium and disodium phosphate required for initial treatment is given in Table 220-30-4. The boiler should not be filled until just before light-off to prevent corrosion due to the oxygenated water. If light-off is postponed for more than 24 hours after a boiler has been freshly filled, the boiler shall be placed under an acceptable layup in accordance with **NSTM Chapter 221** , Section 5.



Key:

1. Feedwater Inlet Valve
2. Feedwater Outlet Valve
3. Feedwater By–pass Valve
4. Funnel Fill Valve
5. Drain Valve
6. Fill Funnel
7. Vent Valve

WARNING

Wear a face shield while pouring concentrated chemicals into the injection tank and while topping off.

1. Ensure that the feedwater injection tank by–pass valve 3 is open and the inlet and outlet valves 1 and 2 are closed.
2. Open the drain valve 5.
3. Open the funnel fill valve 4 and vent valve 7, if installed, to ensure injection tank is empty.
4. When the tank is empty close the drain valve 5.
5. Add the dissolved chemicals to the tank.
6. Top off the injection tank with feedwater through the fill funnel.
7. Close the funnel fill valve 4 and vent valve 7, if installed.
8. Open the injection tank inlet and outlet valves 1 and 2.
9. Close the by–pass valve 3 and allow the feedwater flow to flush the chemicals into the boiler. Record the time the by–pass valve is closed in the boiler water log. If the boiler is steaming, leave the injection tank aligned to the boiler until after the ACA sample has been taken. If the boiler is secured, leave the injection tank aligned to the boiler until boiler water level has been raised two inches.
10. To secure the tank, open the by–pass valve 3 and then close the injection tank inlet and outlet valves 1 and 2.
11. Drain the injection tank by first slowly opening the drain valve 5 and then opening the funnel fill valve 4 and vent valve 7, if installed.
12. Close the drain, funnel fill valves, and vent valve when the tank is empty.

Figure 220-30-3 Waste Heat Boiler Batch Injection Procedure

220-30.37

A waste heat boiler under hydrazine/morpholine lay up may be lit off without draining and flushing. Place the initial dosage of treatment chemicals in the batch injection tank and light-off with the injection tank lined up to the boiler. A boiler containing sodium nitrite solution must be dumped and repetitively flushed prior to being freshly filled and treated. A boiler that has been dumped shall have an initial dose of treatment chemicals placed in the treatment tank prior to light-off. Light-off with the injection tank lined up to the boiler and secure treatment tank when the AOL sample is taken.

220-30.38 PRIOR TO LIGHT-OFF.

The operation of waste heat boiler is dependent on the generator. The boiler operates automatically when the generator is lit off. Therefore a sample is not obtained prior to light-off. Adjustment of the boiler water chemistry, if required, is made based on the after-on-line sample.

220-30.39 STEAMING WASTE HEAT BOILER.

Maintain the boiler water chemistry in a steaming waste heat boiler within the specified limits. Sample and test the steaming boiler as follows:

1. Within 30 minutes after the generator is lit off.
2. As often as required to maintain the limits, but at least every 8 hours (maximum of 8 hours between samples).
3. Within 1 hour before commencing blowdowns.
4. 30 to 60 minutes after blowdown.
5. 30 to 60 minutes after batch chemical treatment.
6. Within 90 minutes prior to securing the generator.

NOTE

Guidance for sampling prior to and during casualty control drills is contained in paragraph 220-31.48.

220-30.40 Alkalinity and Phosphate.

The continuous treatment system should maintain the alkalinity between 0.10 and 0.20 epm and the phosphate between 30 and 50 ppm. Batch treatment will be required if the alkalinity or the phosphate are near or below the lower limit. A logic chart for treatment action of a steaming waste heat boiler is given in Figure 220-30-4.

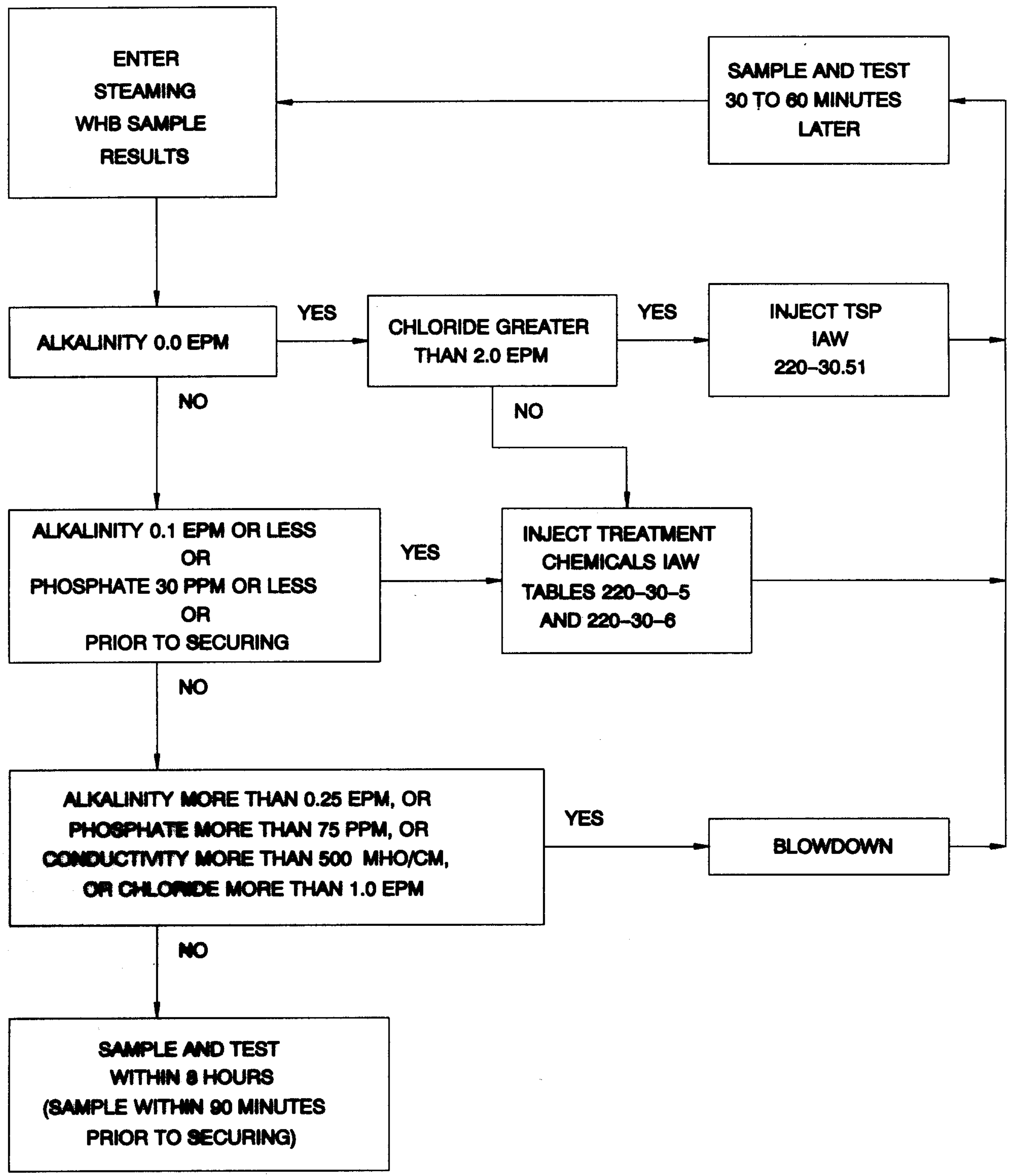


Figure 220-30-4 Logic Chart for Treatment Action of Steaming Waste Heat Boilers

Table 220-30-3 CHEMICAL WEIGHTS NEEDED TO FILL THE CONTINUOUS INJECTION TANK

Boiler Water Volume for Chemical Treatment (Gallons)	Current Tank Level			
	Empty		10 to 20 Gallons	
	TSP	DSP	TSP	DSP
	(Grams)			
100	30	20	25	15
200	60	40	50	30
TSP=Trisodium Phosphate DSP=Disodium Phosphate				

NOTE

When filling a 32 gallon injection tank, add 40 grams TSP and 25 grams DSP when tank is empty. Add 30 grams TSP and 20 grams DSP when tank level is between 5 and 10 gallons.

Table 220-30-4 CHEMICAL WEIGHTS NEEDED FOR FRESHLY FILLING WASTE HEAT BOILERS

Boiler Water Volume for Chemical Treatment(Gallons)	Weights Required for Initial Treatment	
	TSP (Grams)	DSP (Grams)
100	30	22
200	60	45
TSP = Trisodium Phosphate DSP = Disodium Phosphate		

220-30.41 Conductivity.

The conductivity level is controlled by blowdown. The conductivity should be within limits if the alkalinity, phosphate and chloride are maintained properly.

220-30.42 Chloride.

The chloride level of the boiler water is controlled by surface/separator blowdown. When the feedwater quality is properly maintained, a boiler water chloride of less than 1.0 epm can be achieved without difficulty. If the boiler water chloride is difficult to maintain then the source of the contamination must be located and corrected.

220-30.43 CONTINUOUS TREATMENT.

The continuous treatment system does not operate automatically when the generator/boiler is lit off. Within 30 minutes after light-off, assure that the treatment line valves are open (Figure 220-30-2 valves 2, 5, 6, 8, and 9) and the pump is operating. Secure the system as soon as the generator is secured. The tank level shall be monitored to assure that the solution is entering the boiler. Record the tank level in the boiler water log within 30 minutes after light-off and at least every 8 hours. Refill the injection tank when the level drops to between 10 and 20 gallons. The procedures for preparing the treatment solution are given in Figure 220-30-2.

220-30.44

The first time the injection pump is operated, the injection pump stroke shall be set to 60%. This will provide about 1 gallon per hour of treatment solution to the boiler. If batch treatment is required daily and contamination is not occurring, increase the pump stroke in 10% increments until the proper limits are maintained. If the alkalinity and the phosphate are continually over the upper limit, then reduce the pump stroke in 10% increments until the proper level is maintained. Be sure that contamination is not occurring before making any adjustments to the continuous treatment system. Once an operating pump setting has been determined for a specific plant alignment, this setting is recorded in the Waste Heat Boiler Water Chemistry Worksheet Log for successive securings and light-offs. Excessive boiler water carryover will affect the use of the continuous treatment system; refer to paragraph 220-30.69.

220-30.45 BATCH TREATMENT.

The procedure for batch chemical injection is:

WARNING

Wear a face shield when dissolving trisodium phosphate. Concentrated trisodium phosphate solutions are corrosive and cause burns to skin, eyes, and body tissues. Affected personnel shall flush skin with cold water. If trisodium phosphate or its solutions enter the eyes, flush with cold water for 15 minutes and obtain immediate medical attention.

1. Determine the alkalinity and phosphate in the boiler water from the sample test results.
2. Locate the boiler water alkalinity at the top of Table 220-30-5, then read down to find the weight of trisodium phosphate for the appropriate boiler. Record this weight in the log.
3. Go to the last line of the column to find the phosphate correction. This is the amount that the phosphate will increase due to the trisodium phosphate. Record the phosphate correction in the log.
4. Add the phosphate correction to the boiler water phosphate. This gives the corrected phosphate. Record the corrected phosphate in the log.
5. Find the corrected phosphate at the top of Table 220-30-6. Then read down to find the weight of disodium phosphate for the appropriate boiler. Record this weight in the log.
6. Weigh the chemicals, dissolve them in feedwater in the safety dispensing bottle, and inject them into the boiler in accordance with Figure 220-30-3.

Table 220-30-5 TRISODIUM PHOSPHATE DOSAGE FOR WASTE HEAT BOILERS

Boiler Water Volume for Chemical Treatment (Gallons)	Boiler Water Alkalinity, epm				
	0.00 to 0.025	0.05 to 0.075	0.10 to 0.125	0.15 to 0.175	0.20 or more
	Grams of TSP Required to Raise the Alkalinity to 0.20				

Table 220-30-5 TRISODIUM PHOSPHATE DOSAGE FOR WASTE HEAT BOILERS - Continued

Boiler Water Volume for Chemical Treatment (Gallons)	**Boiler Water Alkalinity, epm**				
	0.00 to 0.025	**0.05 to 0.075**	**0.10 to 0.125**	**0.15 to 0.175**	**0.20 or more**
100	30	22	15	7	0
200	60	45	30	15	0
	Phosphate Correction (ppm)				
	20	15	10	5	0
TSP = Trisodium Phosphate					

220-30.46

When the test results indicate that a batch treatment is required, the treatment shall be initiated within 60 minutes after the sample was taken. The dosages will bring the alkalinity to 0.2 epm and the phosphate to 60 ppm.

Table 220-30-6 DISODIUM PHOSPHATE DOSAGE FOR WASTE HEAT BOILERS

Boiler Water Volume For Chemical Treatment (Gallons)	**Corrected Boiler Water Phosphate, ppm**										
	0 to 2.5	**5 to 7.5**	**10 to 12.5**	**15 to 17.5**	**20 to 22.5**	**25 to 27.5**	**30 to 32.5**	**35 to 37.5**	**40 to 42.5**	**45 to 47.5**	**50 or more**
	Grams of DSP Required To Raise Phosphate to 60 ppm										
100	34	31	28	25	22	20	17	14	11	8	0
200	67	62	56	50	45	39	34	28	22	17	0
DSP = Disodium Phosphate											

220-30.47

If required, add treatment chemicals in accordance with the normal dosage tables prior to blowdown to prevent the alkalinity or the phosphate from going below the lower limit. Due to the lower operating pressures, the extent of damage caused by steaming in the free caustic region is much less than for a propulsion boiler. Therefore, blowdown is permissible in the free caustic region to reduce high alkalinity. Add disodium phosphate according to the normal dosage chart to prevent phosphate from going below lower limit.

220-30.48 BOILER WATER CONTAMINATION.

Damage to the boiler or other parts of the plant will occur if the boiler water is seriously contaminated. Refer to paragraph 220-23.8. Criteria for serious contamination, significant damage and moderate contamination are as follows:

Serious Contamination - defined if any of these conditions occur:

1. Alkalinity is less than 0.05 epm.
2. Phosphate less than 10 ppm.

3. Conductivity more than 1500 µmho/cm.

4. Oil visible in samples.

5. Dissolved oxygen in feedwater entering the boiler greater than 15 ppb for 24 hours after detection.

NOTE

The above criteria do not apply to low alkalinity or phosphate in the after light off sample or when hideout is occurring unless other symptoms of contamination are present.

Significant Damage - causing rapid damage will occur if serious contamination deteriorates to any of these conditions:

1. Alkalinity is zero.

2. Alkalinity greater than 2.0 epm.

3. Phosphate is zero.

4. Conductivity is greater than 2000 µmho/cm.

Moderate Contamination - defined as any test result which is outside normal limits but does not meet the conditions of serious contamination or significant damage.

220-30.49 ACTION.

Serious contamination of boiler water is a major casualty that demands immediate corrective actions:

1. Inject chemicals to maintain alkalinity and phosphate.

2. Blowdown to reduce contamination.

3. If treatment actions do not return the boiler water to a condition of moderate contamination or normal limits within four hours, secure the boiler unless the Commanding Officer directs continued operation. If operation must be continued, minimize the firing rate.

4. Locate and isolate the source of the contamination.

Securing the boiler will minimize damage, therefore, do not remain steaming simply to treat the boiler. If the boiler is secured prior to the injection of chemicals, add the chemicals immediately after securing. Only one batch injection may be accomplished after securing, since further chemical additions will not be effective due to inadequate circulation. If after this injection the boiler water continues to meet the serious contamination criterion for a steaming boiler, the boiler must be dumped. Do not light off another boiler if the feedwater is still contaminated. Serious contamination due to seawater or shore water, followed by chemical additions will generate large amounts of sludge. This must be removed by bottom blowdown as soon as the boiler can be secured. The most effective method of eliminating high levels of contamination is to secure, bottom blow, drain, and flush. Bottom blowdown is required even if the boiler is to be dumped due to contamination. Immediate action shall be taken to correct any dissolved oxygen greater than 15 ppb.

220-30.50 REPORTS.

The cognizant activity (for example, ship, NAVSHIPYD, SUPSHIP) shall provide a detailed message report within 24 hours to the Type Commander with an information copy to the ISIC, NAVSEA and NSWCCD-SSES if any of the following conditions occur:

1. The contamination reaches a condition of significant damage as defined in paragraph 220-30.48 for 8 hours or more.
2. The boiler is steamed under conditions of serious contamination for more than 24 hours.

The information to be included in the report is contained in paragraph 220-23.27.

220-30.51 TREATMENT ACTION DURING SEAWATER CONTAMINATION.

Low levels of seawater contamination can be controlled using the normal dosage tables and blowdown. The source of the contamination must be corrected. High levels of seawater contamination require special treatment. When the chloride level in the boiler is over 2.0 epm and the alkalinity is 0.00 epm, inject only trisodium phosphate in accordance with the following formula:

CONSECO TSP = 60 x Chloride

CE TSP = 30 x Chloride

where: TSP = grams trisodium phosphate, dodecahydrate

chloride = boiler water chloride, epm

NOTE

Do not inject more than 500 grams (18 ounces) of trisodium phosphate at one time.

220-30.52 WATER TREATMENT PRIOR TO SECURING.

Within 90 minutes prior to securing, sample the boiler water. Test the sample and treat the boiler if required. If the boiler is secured prior to obtaining the after chemical addition sample, secure the injection tank after the boiler is secured and use the sample taken one hour prior to blowdown as both the after chemical addition and prior to blowdown sample.

220-30.53 BLOWDOWNS.

A separator blowdown (CONSECO) or a surface blowdown (CE) is used to reduce high levels of treatment chemicals or contaminants. A separator/surface blowdown is applied as required by the test results. Periodic bottom blowdowns are used to control sludge buildup. A bottom blowdown is required weekly (no more than 168 steaming hours between bottom blowdowns) and whenever it is secured for more than 2 hours. Wait at least 1 hour after securing to allow the sludge to settle. The steam blanket pressure of 15 psi is sufficient for blowdown. A bottom blowdown is required daily (no more than 24 hours between blowdowns) when the boiler water sample contains sediment. Waste heat boilers do not have to be secured to be given a bottom blowdown. The procedures for blowdown are:

CONSECO: The CONSECO boiler has three bottom blowdown connections: at the separator, the inlet header, and the outlet header. The separator blowdown is used to control high chemical levels. The blowdown procedures are:

1. Obtain permission to conduct a blowdown.
2. Open the overboard discharge valve and the guarding valve.
3a. Separator blowdown: Open the separator blowdown valve three turns. Allow the boiler water level to decrease 3 inches, then secure the valve.
3b. Bottom blowdown: Open the separator blowdown valve fully and then secure. Repeat for the inlet and the outlet header.
4. Close the guarding valve and then the overboard discharge valve.
5. Note the time of completion of the blowdown and record the time in the boiler log.

Combustion Engineering: The CE boiler is equipped with four blowdown connections. The steam drum has a surface blowdown connection. Bottom blowdown connections are on the steam drum, inlet header, and the outlet header. The surface blowdown is used to control high chemical levels. The blowdown procedures are:

1. Obtain permission to conduct a blowdown.
2. Open the overboard discharge valve and the guarding valve.
3a. Surface blowdown: Open the steam drum surface blowdown valve and wait 1 minute, then close the valve.
3b. Bottom blowdown: Open the steam drum bottom blowdown valve fully and then secure. Repeat for the inlet header and the outlet header.
4. Close the guarding valve and then the overboard discharge valve.
5. Note the time of completion of the blowdown and record the time in the log.

220-30.54

The procedures given for a separator/surface blowdown will reduce the alkalinity, phosphate, conductivity, and chloride of a steaming boiler by about 10%. If more than a 10% reduction is indicated, repeat the blowdown cycle as required. Wait 1 minute between each blowdown cycle for the water to circulate. Do not blowdown a steaming boiler more than 50% at one time (five, 3-inch blowdowns on the CONSECO or 5 minutes on the CE). Sample and test 30 to 60 minutes after the blowdown and base further action on the test results. It is required that the percentage of blowdown on a steaming boiler be recorded in the boiler water treatment log. The percent blowdown is determined by using the formula:

$$\% \text{ blowdown} = [\ 100(C_B - C_A)\ ] / C_B$$

where: C_B = Conductivity before blowdown

C_A = Conductivity after blowdown

220-30.55 IDLE BOILER WATER.

Within 1 hour prior to bottom blowdown a boiler water sample shall be obtained and tested. No further testing or treatment is required of an idle waste heat boiler. A sample is not required after bottom blowdown or prior to light-off. Samples of the idle waste heat boiler are not representative. A sample is obtained after securing/prior to blowdown only to assure that the boiler water is not contaminated. If the prior to blowdown test result shows a chloride of more than 1.0 epm or a conductivity of more than 500 µmho/cm then the boiler shall be dumped and flushed. Large increases in the boiler chemical levels after securing are an indication of hideout, refer to paragraph 220-30.66.

220-30.56 WET LAYUP.

Since atmospheric oxygen can be drawn into an idle boiler under wet layup it is important that the proper procedures for maintaining a positive pressure on an idle boiler be used. Wet layup procedures are given here and in the auxiliary boiler section of NSTM Chapter 221, Section 5. As with main propulsion boilers, the prevention of corrosion in auxiliary boiler watersides, often caused by exposure to the atmosphere, is of major concern when securing. The requirements of paragraphs 220-22.62 through 220-22.77, therefore, also apply to auxiliary boilers. The Oil King shall log the layup status of the auxiliary boiler daily on the water chemistry worksheet/log. Factors such as duration of layup, availability of required equipment and type of repair work that will be performed should be considered when choosing the type of layup. The applicability of the layup methods to the various types of auxiliary boilers is given in Table 220-30-7. Include steam blanket, nitrogen blanket, hot deaerated fill, hydrazine/morpholine, and sodium nitrite. These methods are described below.

Table 220-30-7 APPLICABILITY OF WET LAYUP METHODS TO WASTE HEAT BOILERS

	Waste Heat Boilers
Wet Layup	
Steam Blanket	A
Nitrogen blanket	A
Hot deaerated fill[1]	A
Hydrazine/morpholine	A
Sodium nitrite	A
NOTES: A - Applicable N/A - Not applicable	

[1]Applicable to waste heat boilers with operable deaerating feed tanks.

220-30.57 Steam Blanket.

Steam blanket layup is applicable to waste heat boilers. The procedures, materials, lost layup, time limit, disposal, safety precautions, and preparation for light-off requirements listed in paragraph 220-22.72 apply with the following exceptions:

CAUTION

No. 3 waste heat boilers on DD-963/DDG-993/CG-47 class ships are susceptible to freezing and tube damage during extremely cold weather. Dry layup is required for No. 3 waste heat boiler in periods when outside temperatures are expected to be extremely cold to prevent boiler freeze up.

1. A steam supply from another boiler or shore steam up to maximum of the boiler operating pressure is required.
2. Do not add feedwater to the secured boiler after the bottom blowdown.

3. The steam blanket method on waste heat boilers (CG 47 class) is automatic any time the boiler is shut down, providing there is steam pressure on the steam main. When the boiler is shut down and the steam pressure falls to 15 psig, the steam blanketing system will maintain 15 psig. The operator should check the drum pressure gauge hourly. The DD 963 class requires manual opening of steam blanket valves.
4. The boiler shall have been steamed for at least one hour prior to securing. Requirement for the feedwater dissolved oxygen level to be within limits per **NSTM Chapter 220** only applies to ships with DFTs installed (CG-47 Class).

NOTE

During depot level availability, DD-963 class with stainless steel coils may apply a steam blanket following the final hydrostatic test for up to two weeks.

220-30.58 Nitrogen Blanket.

A nitrogen blanket may be used for waste heat boilers. The procedures, materials, lost layup, time limit, disposal, safety precautions, and preparation for light-off requirements listed in paragraph 220-22.73 apply except do not add feedwater to the secured boiler.

220-30.59 Hot Deaerated Fill.

Hot deaerated fill can be used in waste heat boilers with operating deaerating feed tanks. The procedures, material, lost layup, time limit, disposal, safety precautions, and preparation for light-off requirements apply with the following exceptions:

1. When securing, after performing the required blowdown, allow the boiler pressure to reduce to the DFT pressure.
2. Fill the boiler with deaerated feedwater to overflow at vent.
3. Secure the vent valve.
4. Manually close the feed valves at the inlet to the steam separator to prevent boiler drain down.
5. Maintain a positive pressure, not to exceed the boiler operating pressure, using the feedwater pump or head tank.

220-30.60 Hydrazine/Morpholine.

This method is applicable to waste heat boilers but is to be utilized by industrial activities only. Follow paragraph 220-22.71 for layup procedures and precautions with the exception of the following provisions:

1. Prepare sufficient hydrazine/morpholine treated water to fill the boiler and provide a reservoir, approximately double the steaming volume plus 50 to 100 gallons.
2. Maintain a positive pressure not in excess of the boiler operating pressure.

220-30.61 Sodium Nitrite.

This method is applicable for all waste heat boilers. The procedures, materials, lost layup, time limit, disposal, safety precautions, and preparation for light-off requirements listed in paragraph 220-22.74 apply with the following exceptions:

1. Prepare sufficient sodium nitrite solution to fill the boiler and provide a reservoir, approximately double the steaming volume plus 50 to 100 gallons. Dissolve 1 pound of sodium nitrite per 100 gallons of feedwater required in pierside tank or ship's feed tank. Mixing is accomplished by dissolving the sodium nitrite in feed-quality water (10 pounds will dissolve in 2 gallons of water), and the adding the dissolved chemicals to the feedwater in the tank. The tank is then recirculated for 30 minutes to mix the solution.
2. A head tank is the easiest and the preferred method of maintaining positive pressure. If a head tank method is used, locate and pipe the head tank above the highest boiler vent.
3. Fill the boiler with sodium nitrite solution and maintain pressure using a head tank or feed pump.

220-30.62 DRY LAYUP.

The waste heat boiler shall be dumped and flushed prior to dry layup. After the boiler has been flushed with feed quality water, the boiler watersides shall be completely dried by operating the gas turbine generator for 30 minutes. If the generator cannot be operated, the boiler shall be dried using hot air. A sodium nitrite flush is not added to the boiler prior to dry layup. Refer to **NSTM Chapter 221** , section 5 for dry layup.

220-30.63 DRY OPERATION.

Waste heat boilers shall only be operated in a dry condition when an equipment casualty prevents normal boiler operation and operation of the associated gas turbine generator is required. The boiler shall be dumped and flushed prior to dry operation whenever possible. This is to prevent baking waterside deposits on the tube surfaces and from concentrating the boiler water chloride on the stainless steel tubes in CONSECO boilers. If it becomes necessary to place the boiler in dry operation while the gas turbine generator is operating, the header and separator blowdown valves should be opened to drain the boiler as quickly as possible. The boiler shall be flushed after the generator is secured and the boiler has cooled for at least 4 hours. The procedures for dry layup and dry operation are provided in **NSTM Chapter 221** and the boiler technical manuals.

220-30.64 DUMP AND FLUSH.

The waste heat boiler is dumped and flushed due to high chemical levels or in preparation for dry operation or layup. Dumping the boiler will zero the hours for bottom blowdown. To dump the boiler, secure the generator and allow the boiler pressure to drop to steam blanket pressure. Apply the steam blanket and open all the bottom blow valves and allow the boiler to drain to the bilge. Secure the valves when the boiler is empty. Then open each valve, one at a time, to assure all circuits are empty. To flush the boiler, fill with feedwater using the boiler feed pump until water flows from the boiler vent. Operate the circulating pump for 5 minutes to circulate the feedwater through the generating bank and then dump. The boiler feed pump must be operating while the circulating pump is operating to provide a mechanical seal water supply to the circulating pump.

220-30.65 WASTE HEAT BOILER CHEMISTRY CONTROL PROBLEMS

220-30.66 CHEMICAL HIDEOUT.

The chemical hideout seen in waste heat boilers is caused by boiler tube dry out. All of the water in one or more tubes or circuits is converted to steam which results in the chemicals being deposited on the waterside surfaces. Hideout may occur at high generator loads due to the inherent design of these boilers. However, when hideout occurs at all generator loads, a mechanical problem is indicated. The cause of this excessive hideout can be low circulation flow rates, poor gas flow distribution or excessive waterside deposits. Low circulation flow rates can result from backward rotation of the circulation pump or excessive wear of circulation pump impeller and wear rings. A restriction in the circulating pump discharge piping, gate valve, flow control orifices (CG-47), or restrictor plugs (DD-963) can also cause low flow rates. A gas lane can be created across the top of the tube coil in a DD-963 class WHB due to excessive clearance between the cinch cover and the coil. This results in an increased gas flow around the top tube, resulting in transfer of more heat to the upper tube coils causing these tubes to dry out.

220-30.67 Detection.

The symptoms of chemical hideout are a decrease in all of the boiler water parameters usually associated with an increase in generator load. The chemicals return when the load is reduced. If hideout is confirmed and operation must be continued, then maintain a minimum of 0.025 epm alkalinity and 5 ppm phosphate. Batch inject only if at or below these limits using the normal dosage tables. High chemical levels due to a decrease in generator load are controlled by blowdown. If hideout is suspected, secure the boiler and allow to cool. Recirculate the boiler water for about 5 minutes and then obtain a boiler water sample. If the chemical level more than doubles, hideout is confirmed. If symptoms persist, seek TYCOM/NAVSEA/NSWCCD-SSES assistance.

220-30.68 Action.

Occasional incidents of hideout may occur when the generator is operating at high load. Reducing the generator load will stop the hideout. Do not continue to batch inject treatment chemicals if hideout is confirmed. Maintain a minimum of at least 0.025 epm alkalinity and 5 ppm phosphate. When the boiler is secured, it shall be drained and flushed repeatedly until a sample of the flush water shows chemical levels to be within limits. Excessive hideout requires that the mechanical problem be corrected. Problems with poor circulation will not necessarily cause low discharge pressure. Examination of the pump and valves is required. If excessive waterside deposits are suspected, the boiler watersides should be inspected to determine the need for chemical cleaning. Report the inspection results to NAVSEA/NSWCCD-SSES for further guidance.

220-30.69 CARRYOVER.

The amount of boiler water that leaves the boiler with the steam is given by the percent carryover. The waste heat boilers are supposed to have less than 1 percent carryover; however, many of the waste heat boilers have been found to have much higher levels of carryover. High levels of carryover allow boiler treatment chemicals and any contaminants to enter the steam/condensate system. This can cause deterioration of the piping and formation of deposits in the steam lines. As long as only one boiler is steaming the effects on the boiler water chemistry will be minimal. Most of the chemicals that leave the boiler will be washed to the feedwater tank and then returned to the boiler. However, when two boilers are steaming that have different rates of carryover the chemicals that leave the boiler will be mixed at the feedwater tank and fed to both boilers. The boiler with the higher carryover rate will lose chemicals to the other boiler. The boiler with the higher carryover will require frequent injections while the other will require frequent blowdowns. During the light-off of a waste heat boiler a large amount of boiler water will carryover. Similarly, when a boiler is secured, boiler water can carry over or drain back to the feedtank and contaminate the other boiler. These incidences during light-off and securing will cause an increase in the chemical level of another boiler that is steaming.

220-30.70 Detection.

Excessive carryover can be seen in the boiler water logs. When two boilers are steaming, an increase in the chemical levels in one boiler, while the other loses chemicals, is an indication of carryover. Each of the boilers may carryover at different rates; therefore, when a different set of boilers is steaming the boiler that was losing chemicals may gain chemicals. Excessive carryover will cause the salinity/conductivity indicators to read higher than the chemical chloride test. The detection of alkalinity in the condensate or the feedwater is also a sign of carryover (feedwater sample pink to phenolphthalein).

220-30.71 Action.

The treatment procedures are designed to compensate for some carryover. The batch dosage does not increase the alkalinity or the phosphate to the upper limits to allow for some increase in chemicals. The low treatment levels reduce the amount of chemicals that leave a boiler having excessive carryover. When it is known that one boiler carries over more than another, secure the continuous treatment system to the boiler that is collecting the chemicals. Adjust the continuous treatment to the boiler that is carrying over to maintain the chemical levels as low as possible. Excessive carryover may cause the indicator alarms to actuate, if this occurs bypass the alarm. When contamination occurs, the boiler water chloride will carryover and cause high chloride test results in the feedwater. It is more effective to blowdown the boiler to reduce the contamination than to dump feedwater. If the carryover is so severe that it is impossible to maintain the water chemistry, then a problem with the steam separator may be indicated. If symptoms of severe carryover are persistent seek TYCOM/NAVSEA/NSWCCD-SSES assistance.

220-30.72 WASTE HEAT BOILER FEEDWATER AND BOILER WATER SAMPLING AND TESTING

220-30.73

Section 24, Techniques and Section 25, Safety, pertain to the waste heat boilers. The procedures for sampling are given in Section 26.

220-30.74 WASTE HEAT BOILER FEEDWATER TESTS.

The feedwater tests for the waste heat boiler are the same as those for propulsion boilers. The feedwater tests are:

Feedwater Chloride Test (paragraph 220-26.17)

Feedwater Hardness Test (paragraph 220-26.18)

Dissolved Oxygen Test (paragraph 220-26.19)

Salinity Indicator Testing (paragraph 220-26.22)

220-30.75 WASTE HEAT BOILER WATER TESTS.

The chloride, conductivity, alkalinity, and phosphate tests for auxiliary boilers are the same as for propulsion boilers. The boiler water tests are:

Boiler Water Conductivity Test (paragraph 220-26.30)

Boiler Water Chloride Test (paragraph 220-26.31)

Boiler Water Alkalinity and Phosphate Test (paragraph 220-26.28)

220-30.76 STANDARDS TESTING.

The standard tests are run quarterly, when new nitric acid or mercuric nitrate reagent is prepared, and whenever test results are suspected. Interpret the test results according to paragraphs 220-24.59 through 220-24.64. The procedures are:

Standard	Procedure
Feedwater Hardness	220-26.18

Boiler Water Conductivity	220-26.30
Boiler Water Chloride	220-26.31
Alkalinity	220-26.34

220-30.77 WASTE HEAT BOILER RECORD MAINTENANCE

220-30.78

The personnel responsibilities and the general information given in Section 27 applies to the waste heat boilers. There are six forms available for recording the necessary data used to assist in maintaining proper water conditions in a waste heat steam plant. The records are:

1. Cover Sheet and Monthly Boiler Data, NAVSEA 9255/6 (6-94).
2. Boiler Water/Feedwater Test and Treatment Chemical Inventory Log, NAVSEA 9255/16 (6-94),(COMMANDING OFFICER DISCRETION).
3. Auxiliary/Waste Heat Feedwater Chemistry Worksheet/Log, NAVSEA 9255/17 (6-94).
4. Waste Heat Boiler Water Chemistry Worksheet/Log, NAVSEA 9255/7 (6-94).
5. Fuel and Water Report, NAVSEA 9255/9 (6-94),(COMMANDING OFFICER DISCRETION).

220-30.79

A complete Steam Plant Water Treatment Log Package shall be compiled each month. This package is retained for 2 years and shall consist of:

1. The cover sheet and monthly boiler data.
2. The daily auxiliary/waste heat feedwater chemistry worksheet/logs.
3. The daily waste heat boiler water chemistry worksheet/logs for each boiler.

220-30.80 COVER SHEET AND MONTHLY BOILER DATA.

This form is maintained as in paragraph 220-27.9 by entering the appropriate data. Enter NA (not applicable) in the Water Jet, Wirebrush, or EDTA Waterside Cleaning section. Replace **FIRESIDE CLEANING** section with **TUBE BUNDLE REPLACED, DATE,** and **STM. HRS. SINCE** .

220-30.81 BOILER WATER/FEEDWATER TEST AND TREATMENT CHEMICAL INVENTORY LOG.

This log is maintained as in paragraph 220-27.10 by entering the appropriate data.

220-30.82 AUXILIARY/WASTE HEAT FEEDWATER CHEMISTRY WORKSHEET/LOG.

This daily log (Figure 220-30-5, sheets 1 and 2) is maintained as in paragraph 220-29.70 with the exception that the Deaerated Feedwater Section is used on ships with DFTs.

AUXILIARY/WASTE HEAT FEEDWATER CHEMISTRY WORKSHEET/LOG

SYSTEM 1 SHIP USS CRUISER (CG-65) DATE 4 JUN 94 PAGE 15

CHEMICAL TESTS AND SALINITY/CONDUCTIVITY INDICATOR COMPARISON (REQUIRED DAILY) NOTE: µmho/cm/145=epm

TIME	INDICATOR LOCATION	CHLORIDE ml MERCURIC NITRATE x0.1= epm CHLORIDE		INDICATOR READING		COM-PARISON	HARDNESS ml EDTAx0.2= epm HARDNESS		OIL KING INITIAL
		ml	epm	µmho/cm	epm	SAT/UNSAT	ml	epm	
0226	CNTRL COND #1	.2	.02	5.8	.04	SAT			RE
0236	CNTRL COND #2	.2	.02	4.35	.03	SAT			RE
0243	CONDEN DRN 2	.3	.03	2.9	.02	SAT			RE
0318	HTR DRNS #1	.1	.01		.05	UNSAT	.1	0.02	RE
0328	FINAL DISTL.	.3	.03		.04	SAT			RE

FEEDWATER TESTS

TIME	LOCATION	INDICATOR READING µmho/cm or epm	CHLORIDE ml MERCURIC NITRATE x0.1= epm CHLORIDE		HARDNESS ml EDTAx0.2= epm HARDNESS		OIL KING INITIAL
			ml	epm	ml	epm	
0214	AIR EJEC #1	0	.2	.02			RE
0255	AIR EJEC #1	.03	.2	.02			RE
0702	HTR DRNS #1	.05	.1	.01			RE
0836	COND DRNS #2	12					MJ
0845	COND DRNS #2	13	1.1	.11			MJ
0858	COND DRNS #2	4.35	.3	.03			MJ

DEAERATED FEEDWATER

TIME	DFT	CODE	DISSOLVED OXYGEN 15 ppb MAX
0435	#2	RTE	12.5

LEGEND/TEST CODE

- AOL 2 TO 3 HOURS AFTER GENERATOR LIGHT-OFF
- RTE WITHIN 24 HOURS
- OTH OTHER

NAVSEA 9255/17 (6-94)(FRONT) NSN 0116-LF-018-3100

Figure 220-30-5 Auxiliary/Waste Heat Feedwater Chemistry Worksheet/Log (Sheet 1 of 2)

AUXILIARY/WASTE HEAT FEEDWATER CHEMISTRY WORKSHEET/LOG

PAGE 16

TIME	REMARKS:
0214	AIR EJECTOR DRAINS #1 – SALINITY INDICATOR CONSTANTLY READING 0, CONTACTED IC2 REED TO CHECK THE OPERATION OF THE SALINITY INDICATOR. SAMPLE AND TEST AIR EJECTOR DRAINS EVERY 4 HOURS UNTIL INDICATOR IS CORRECTED.
0255	AIR EJECTOR DRAINS #1 – REPAIRED LOOSE WIRE ON SALINITY INDICATOR. DISCONTINUED 4 HOUR TESTING.
0318	HEATER DRAINS #1 – CONTACTED IC2 REED TO CHECK THE OPERATION OF THE SALINITY INDICATOR. SAMPLE AND TEST HEATER DRAINS EVERY 4 HOURS UNTIL INDICATOR IS CORRECTED.
0702	HEATER DRAINS #1 – IC2 REED CHECKED THE OPERATION OF THE SALINITY INDICATOR. UNABLE TO CORRECT UNTIL DISTILLER IS SECURED. CONTINUE 4 HOUR SAMPLING AND TESTING OF HEATER DRAINS UNTIL INDICATOR CORRECTED.
0836	CONDENSATE DRAINS #2 – CONDUCTIVITY ALARM SOUNDED. LOCATE AND ISOLATE SOURCE OF CONTAMINATION, SAMPLE AND TEST THE ON-LINE BOILER(S).
0845	CONDENSATE DRAINS #2 – CHEMICALLY TESTED FOR CHLORIDE. LOCATE AND ISOLATE CONTAMINATION SOURCE. SAMPLE AND TEST THE ON-LINE BOILER(S).
0846	BYPASSED CONDENSATE DRAINS COOLER, TAG OUT AND INSPECT COOLER FOR TUBE LEAK.

SHORE STEAM & SHORE SOURCE FEEDWATER SUPPLIER REQUIREMENTS (MAXIMUM)	SHORE STEAM/ CONDENSATE	PROCESSED FEEDWATER
CONDUCTIVITY, µmho/cm	25	2.5
HARDNESS, epm	0.10	–
DISSOLVED SILICA, ppm	0.2	0.2
pH (RANGE)	5.0 TO 9.5	–
TOTAL SUSPENDED SOLIDS, ppm	0.10	–

REQUIREMENTS/LIMITS (MAXIMUM)	SALINITY INDICATOR epm	CONDUCTIVITY µmho/cm	CHLORIDE epm	HARDNESS epm
DISTILLATE	0.065	10.0	0.07	–
DISTILLER AIR EJECTOR DRAINS	0.065	10.0	0.05	–
RESERVE/MAKE-UP/IDLE FEEDWATER	0.10	15.0	0.10	0.10
CONDENSATE/DRAINS/FEEDWATER	0.05	8.0	0.05	0.02
SHORE SOURCE FEEDWATER	–	<40	–	0.10

LCPO INITIAL	LCPO DATE	MPA INITIAL	MPA DATE	REVIEWED: (ENGINEER OFFICER)	DATE
MBP	5Jun94	JAJ	5Jun94	John B.K. Sullivan	5 June 1994

NAVSEA 9255/17 (6-94)(BACK)

NSN 0116-LF-018-3200

Figure 220-30-5 Auxiliary/Waste Heat Feedwater Chemistry Worksheet/Log (Sheet 2 of 2)

220-30.83 Deaerated Feedwater Section.

Maintain this section feedwater as follows:

1. Enter time of completion of sampling.
2. Enter DFT number.
3. Enter appropriate code.
4. Enter the dissolved oxygen test result.

220-30.84 WASTE HEAT BOILER WATER CHEMISTRY WORKSHEET/LOG.

The log (Figure 220-30-6, sheet 1) consists of the following sections:

1. Chemical Test Results.
2. Batch Chemical Treatment.
3. Continuous Chemical Treatment.
4. Blowdown.
5. Steaming Hours Data.
6. Remarks.

WASTE HEAT BOILER WATER CHEMISTRY WORKSHEET/LOG

BOILER NO. 1 SHIP USS WASTE HEAT (CG-51) DATE 25 JUNE 1994 PAGE 60

TIME	CODE	CONDUCTIVITY LIMIT: 500 µmho/cm		ALKALINITY RANGE: 0.05–0.25 epm		PHOSPHATE RANGE: 25 – 75 ppm		CHLORIDE LIMIT: 1.0 epm		CONTINUOUS INJECTION TANK LEVEL	INLET GAS TEMP.	OIL KING INITIAL	EOOW/ EDO INITIAL
		TEMP. (°C)	µmho/cm CONDUC-TIVITY	ml PHENOL-PHTHALEIN	ml/4 = epm ALKALINITY	ml METHYL PURPLE	mlx25 = ppm PHOSPHATE	ml MERCURIC NITRATE	mlx0.4 = epm CHLORIDE	(gallons)	(°F)		
0001	STM												
0430	LOF												
0455	AOL	25	180	.4	0.100	1.2	30	1.5	0.6	20	450	PH	BJE
0930	OTH	25	340	CS	0 BWS	0.8	20 BWS	5.7	2.04 BWS	16	510	KG	RB
0945	ADD												
0947	OTH												
1020	ACM/TB	26	450	.7	0.175	1.6	40	5.3	2.12 BWS	15	650	KG	RB
1040	S												
1125	ABD	25	310	.5	0.125	1.1	27.5	3.8	1.52 BWS	14	640	KG	RB
1145	ADD												
1225	ACM/TB	25	400	.8	0.200	2.3	57.5	3.8	1.52 BWS	13	650	RW	RJP
1245	S												
1330	ABD	25	240	.5	0.125	1.3	32.5	2.3	0.92	12	650	RW	RJP
2020	RTE	25	250	.6	0.150	1.3	32.5	2.3	0.92	45	650	PH	BJE

BATCH CHEMICAL TREATMENT					
TIME	TRISODIUM PHOSPHATE (grams)	TSP CORREC-TION FOR PHOSPHATE	CURRENT PHOSPHATE LEVEL	CORRECTED PHOSPHATE	DISODIUM PHOSPHATE (grams)
0945	61				
1145	15	10	27.5	37.5	14

TOTAL TSP INJECTED 76 TOTAL DSP INJECTED 14

CONTINUOUS CHEMICAL TREATMENT		
TIME	TSP (grams)	DSP (grams)
1530	25	15

PUMP STROKE % 50

BLOWDOWN				
TIME	TYPE	CONDUCTIVITY BEFORE	CONDUCTIVITY AFTER	% BLOW-DOWN
1040	S	450	310	31
1245	S	400	240	40

TOTAL PERCENT BLOWDOWN 71

NAVSEA 9255/7 (6-94)(FRONT) NSN 0116-LF-018-2400

Figure 220-30-6 Waste Heat Boiler Water Chemistry Worksheet/Log (Sheet 1 of 2)

WASTE HEAT BOILER WATER CHEMISTRY WORKSHEET/LOG

PAGE 61

TIME	REMARKS:
0450	OTH- Placed continuous treatment system on-line.
0930	OTH- Contamination found in feedwater system from distillate, seawater
	contamination, significant damage, batch treat with casualty dose of
	TSP, 30-60 ACA.
0947	OTH- Source of contamination isolated.
1020	ACA/PTB- Moderate seawater contamination, conduct 3-10 percent
	surface blowdowns, 30-60 ABD.
1125	ABD- Moderate seawater contamination, batch treat with TSP/DSP,
	30-60 ACA.
1225	ACA/PTB- Moderate seawater contamination, conduct 5-10 percent
	surface blowdowns, 30-60 ABD.

	STEAMING HOURS	STEAMING HOURS UNDER CONTAMINATION: MODERATE	SERIOUS
PRIOR HOURS STEAMED THIS MONTH	346.2	13.8	0
HOURS STEAMED TODAY	19.5	3.2	0.8
HOURS STEAMED THIS MONTH	365.7	17.0	0.8
HOURS SINCE LAST WATERSIDE INSPECTION	873		
HOURS SINCE LAST GASSIDE INSPECTION	873		
HOURS SINCE LAST BOTTOM BLOWDOWN	19.5		
HOURS DRY OPERATION TODAY	0		
TOTAL HOURS DRY OPERATION	253		

LEGEND/TEST CODE

AOL WITHIN 30 MIN. AFTER LIGHT OFF
RTE WITHIN 8 HOURS
ADD BATCH CHEMICAL INJECTION
ACA 30 TO 60 MIN. AFTER CHEMICAL ADDITION
PTB WITHIN 60 MIN. PRIOR TO BLOWDOWN
ABD 30 TO 60 MIN. AFTER BLOWDOWN
FFT FRESHLY FILLED AND TREATED
LOF GENERATOR LIGHT OFF (STEAMING)
GEN GENERATOR LIGHT OFF (DRY)
SEC GENERATOR SECURED
D BOILER DRAINED
OTH OTHER
PTS WITHIN 90 MIN. PRIOR TO SECURING

BOILER LAYUP

DRY LAYUP
DES DESICCANT
HTD HEATED AIR

WET LAYUP
STM STEAM (SHIP)
STS STEAM (SHORE)
NIT NITROGEN
DFT HOT DFW FILL
HYD HYDRAZINE
SN SODIUM NITRITE

BLOWDOWNS
S SURFACE/SEPARATOR
B BOTTOM

LCPO INITIAL	LCPO DATE	MPA INITIAL	MPA DATE	REVIEWED: (ENGINEER OFFICER)	DATE
RCM	26 Jun 94	[illegible]	26 Jun 94	[illegible] B.W. [illegible]	26 June 1994

NAVSEA 9255/7 (6-94)(BACK) NSN 0116-LF-018-2400

Figure 220-30-6 Waste Heat Boiler Water Chemistry Worksheet/Log (Sheet 2 of 2)

220-30.85

Initiate the daily log for each boiler by entering the boiler number, the ship name and hull number, and the date.

220-30.86

Chemical Test Results section shall be maintained as follows:

1. Enter the time on a 24 hour clock basis and the appropriate code for:
   a. Completion of boiler sampling.
   b. Generator light-off (boiler steaming or dry).
   c. Commencement of batch chemical addition.
   d. Completion of blowdown.
   e. Generator secured.
   f. Completion of freshly filling the boiler.
   g. Completion of draining the boiler.
   h. Completion of flushing the boiler.
   i. Commencement and completion of full layup conditions.
   j. Other items of interest.
2. Record the test results for each sample.
3. Record the continuous injection tank level and generator gas inlet temperature for each sample (WHB steaming).
4. The analyst and the reviewing EOOW initial the log upon completion of the test.

220-30.87

The Batch Chemical Treatment section shall be maintained as follows:

1. Enter the time that the chemical injection is initiated.
2. Enter the grams of trisodium phosphate required.
3. Enter the phosphate correction that will be caused by the addition of trisodium phosphate.
4. Enter the phosphate reading obtained from the sample result.
5. Add the correction to the original phosphate reading and enter the corrected phosphate.
6. Enter the amount of disodium phosphate required.
7. Enter the total amounts of chemicals used for the day.

220-30.88

The Continuous Chemical Treatment section shall be maintained as follows:

1. Enter the time the continuous treatment tank is filled.
2. Enter the grams of trisodium and disodium phosphate used to prepare the continuous injection tank.

3. Enter the percent pump stroke. Changes in pump stroke are entered in remarks.

220-30.89

The Blowdown section shall be maintained as follows:

1. Enter the time of completion of the blowdown operation.
2. Enter the appropriate code for surface or bottom blowdown as given on the back of the log.
3. Enter the conductivity before blowdown, the conductivity after blowdown, and the calculated percent blowdown for a steaming boiler.
4. Enter the total percent blowdown on a steaming boiler for the day.

220-30.90 Steaming Hours Data Section.

This section (Figure 220-30-6, sheet 2) shall be completed by entering into the **prior hours steamed this month** blocks the **steaming hours** and **steaming hours under moderate** and **serious contamination** from the **hours steamed this month** blocks of the previous day's log. For the first day of the month, enter zeros into the **prior hours steamed this month blocks** . Enter into the **hours steamed today** blocks the current day's **steaming hours** and **steaming hours under moderate** and **serious contamination** . **Steaming hours** are recorded to the nearest 0.1 hours from light-off to securing. **Steaming hours under contamination** start from the sample time when the contamination was detected to the sample time when the boiler water conditions are back within limits or the boiler is secured. Add the **prior hours steamed this month** to the **hours steamed today** to obtain the **hours steamed this month** . Enter the **hours since last waterside inspection, gasside inspection, bottom blowdown** and **hours dry operation today** (cross out fireside on the log and replace with gasside). Add the **total hours dry operation** from the previous day's log to the current day's **hours of dry operation** to obtain the **total hours dry operation. Total hours of dry operation** are cumulative for the life of the coil/generating tube bank and are only rezeroed when the entire coil/generating tube bank has been replaced. If more than one log is used for the boiler in any one day, then enter the data on the last log for the day.

220-30.91 Remarks Section.

The remarks section shall describe significant events of the day related to that boiler. Additional pages for remarks shall be inserted as necessary. All remarks are accompanied by the time as appropriate. If a doubt exists as to whether or not an entry should be made in the remarks section, enter it. The following types of events shall be recorded:

1. The setting of boiler safety valves.
2. Hydrostatic tests, including purpose and pressure, and the signature of the witnessing individual.
3. A brief summary of boiler repairs accomplished.
4. Boiler inspection.
5. Explanation of each test result which is out of limits.
6. Description of unusual conditions.
7. The results of tests of the boiler water/feedwater chemicals against standards, except the quarterly tests, are entered on the log for WHB-1. (The results of the quarterly standard test results are entered on the monthly boiler data.)

220-30.92

The Waste Heat Boiler Water Chemistry Worksheet/Log need not be prepared on a daily basis when the boiler is idle. When no testing is required and no change in boiler condition is occurring, enter the inclusive dates on the front of one log and enter the type of layup applied in the code column. Describe significant events occurring during the idle period.

220-30.93

For every day that there is a log, the LCPO shall review and initial the log.

220-30.94 FUEL AND WATER REPORT (OPTIONAL AT COMMANDING OFFICER'S DISCRETION).

This form is maintained as in paragraph 220-27.36 by entering the appropriate data.

220-30.95 WASTE HEAT BOILER SUPPLY INFORMATION

220-30.96

The general information contained in Section 28 also applies to waste heat boiler supplies. Specific material recommendations for waste heat boilers are contained in Table 220-30-8.

220-30.97 FORMS.

The following forms are used to record water conditions in waste heat boiler systems. They may be obtained through normal supply channels in accordance with NAVSUP Publication 2002.

1. NAVSEA 9255/6 (6-94), NSN 0116-LF-018-2300, Cover Sheet and Monthly Boiler Data.
2. NAVSEA 9255/7 (6-94), NSN 0116-LF-018-2400, Waste Heat Boiler Water Chemistry Worksheet/Log.
3. NAVSEA 9255/9 (6-94), NSN 0116-LF-018-2600, Fuel and Water Report.
4. NAVSEA 9255/16 (6-94), NSN 0116-LF-018-3100, Boiler Water/Feedwater Test and Treatment Chemical Inventory Log.
5. NAVSEA 9255/17 (6-94), NSN 0116-LF-018-3200, Auxiliary Waste Heat Feedwater Chemistry Worksheet/Log.

Table 220-30-8 WASTE HEAT BOILER, RECOMMENDED ONBOARD STOCK FOR 6-MONTH DEPLOYMENT

Item	NSN	Unit of Issue	Qty Per Ship
BASIC EQUIPMENT			
Boiler water testing cabinet (complete)	1H 6630-00-372-0839	EA	1
Boiler water conductivity test equipment	All items in 220-28.6	N/A	1
Dissolved oxygen testing kit (complete)	9G 6635-01-044-6065	KT	1/DFT
Hardness test equipment	All items in 220-28.9	N/A	1
STOCK CHEMICALS			

Table 220-30-8 WASTE HEAT BOILER, RECOMMENDED ONBOARD STOCK FOR 6-MONTH DEPLOYMENT - Continued

Item	NSN	Unit of Issue	Qty Per Ship
Ampoules, 0-40 ppb oxygen	9L 6630-01-068-5210	BX	7/DFT
Chloride indicator	9G 6810-00-753-4907	BT (12)	1
Dimethylglyoxime	9G 6810-01-082-5414	BT (25 g)	1
Hardness buffer	9G 6850-01-390-4335	BT (100 g)	1
Hardness indicator	9G 6850-01-390-4339	BT (100 g)	1
Hardness titrating solution	9G 6810-01-072-1978	GL	1
Isopropyl alcohol (isopropanol, 2-propanol)	9G 6810-00-227-0410	GL	1
Mercuric nitrate	9G 6810-00-281-4163	BT (4 oz)	4
Methyl purple indicator	9G 6810-00-142-9290	BT (12)	1
Nitric acid	9G 6810-00-270-9978	QT	4
Phenolphthalein indicator	9G 6810-00-223-7612	BT (100 g)	1
SPARE EQUIPMENT			
Aspirator bulb assembly (for filling burets)	1H 6640-00-291-1162	EA	2
Balance, triple beam	9G 6670-00-641-7341	EA	1
Bottle, dropper, 60 ml, plastic	9L 6640-01-077-2468	PG (12)	1
Bottle, polyethylene, screw cap, 1 qt	9G 8125-00-819-6085	EA	12
Bottle, reagent, 1 liter (for nitric acid)	9L 6640-00-253-2495	EA	1
Bottle, reagent, 1 liter (for mercuric nitrate)	9L 6640-00-702-2540	EA	1
Bottle, square, 8 oz	9G 8125-00-543-7699	EA	2
Bottle, wash, plastic, 500 ml	9L 6640-00-314-2097	EA	1
Buret assembly, automatic zero, 10 ml, for hardness	1H 6640-01-072-1980	EA	2
Buret, automatic zero, 10 ml, for chloride, alkalinity, and phosphate	9L 6640-00-264-6951	EA	3
Casserole, porcelain, white	9L 6640-00-412-8400	EA	2
Cell, conductivity, dip type,constant of 2.0	1H 6630-00-620-4540	EA	1
Comparator, 0-40 ppb oxygen	9L 6630-01-035-1864	EA	1/DFT
Cooler, sample, boiler water	1H 4420-00-376-1545*	EA	1
Cooler, sample, DFT	1H 4420-00-376-1545*	EA	1
Cylinder, graduated, 100 ml	9L 6640-00-420-0000	EA	3
Dipper, brass	9C 4410-01-077-2467	EA	4
Grease, ground glass joint, silicone	9G 9150-00-965-2408	TU (150 g)	1
Jerrican, plastic, 5 gal	9L 6640-01-083-9756	EA	2
Jug, safety, plastic, 2 1/2 gal	9L 6640-01-083-9755	EA	2
Meter, conductivity Solubridge	9N 6625-00-620-4539	EA	1
Rod, stirring, 7 in long	9L 6640-00-290-0154	EA	6
Sampler, glass, dissolved oxygen	9L 6640-01-045-0821	EA	4/DFT
Scoop, plastic	9Q 7330-01-079-0694	DZ	1
Snapper, dissolved oxygen	9Q 5120-01-090-5860	EA	5/DFT
Spatula, nickel-plated steel	9L 6640-00-171-5198	EA	2
Stopper, rubber, size 9	9L 6640-00-935-1108	PG (15)	1
Thermometer, metal, dial type (0 to 100°C)	9G 6685-00-663-8093	EA	2
Tubing, neoprene, 3/16 in ID, dissolved oxygen	9C 4720-00-529-5015	FT	3/DFT

Table 220-30-8 WASTE HEAT BOILER, RECOMMENDED ONBOARD STOCK FOR 6-MONTH DEPLOYMENT - Continued

Item	NSN	Unit of Issue	Qty Per Ship
SAFETY EQUIPMENT			
Apron, rubber	9Q 8415-00-634-5023	EA	2
Face shield	9Q 4240-00-542-2048	EA	2
Finger cot	9L 6515-00-935-1194	PG (144)	2/DFT
Gloves, rubber	9D 8415-00-266-8677	PR	6
Gloves, plastic	9D 8415-00-682-6786	PR	100
Goggles	9G 4240-01-364-2169	PR	2
STANDARDS			
Chloride (2.0 epm)	9G 6810-01-129-3762	BT (75 ml)	12
Conductivity (1400 µmho/cm)	9G 6810-00-945-7682	BT (250 ml)	12
Hardness (0.2 epm)	9G 6810-01-125-5234	BT (150 ml)	8
Methyl purple alkalinity (6.0 epm)	9G 6810-01-259-8231	BX(6-100 ml btl)	2
TREATMENT CHEMICALS			
Caustic soda (lye, sodium hydroxide)	9Q 6810-00-270-8177	BT (500 g)	1
Desiccant, 1 lb bag Desiccant, 1/2 lb bag	9G 6850-00-264-6572 9G 6850-00-264-6571	DR (150 bags) DR (300 bags)	1 1
Disodium phosphate anhydrous (sodium phosphate, dibasic, O-S-639)	9G 6810-00-584-4298	DR (25 lb)	2
Humidity indicator card	9G 6685-00-752-8240	CN (125)	1
Trisodium phosphate dodecahydrate (sodium phosphate, tribasic, dodecahydrate, O-S-642, Type II)	9G 6810-01-082-5415	DR (25 lb)	4

*The same cooler is used for boiler water, desuperheated steam and DFT.

SECTION 31.

REQUIREMENTS FOR PROPULSION BOILER COORDINATED PHOSPHATE TREATMENT

220-31.1 INTRODUCTION.

This section provides the requirements for coordinated phosphate treatment of main propulsion boilers. Most of the information provided in Section 20 through Section 28 is applicable to coordinated phosphate treatment. Morpholine treatment of condensate is also included. Information in this section covers two types of main propulsion boilers:

1. Type A: All propulsion boilers with up to 600 psi (4,100 kpa) nominal operating pressure which are not listed below as Type B.
2. Type B: All propulsion boilers with 1,200 psi (8,300 kpa) nominal operating pressure, and the propulsion boiler in the following ships:
   a. LHA 1 through LHA 5
   b. AGF 3 and AGF 11 (formerly LPD 3 and LPD 11)

c. LPD 1, LPD 2, LPD 4, through LPD 10, and LPD 12 through LPD 15
d. LSD 32 through LSD 34 and LSD 36
e. AOE 1 through AOE 4
f. CV 59
g. FF 1037 and FF 1038
h. BB 61 through BB 64

Many of the above ships have been converted to chelant treatment. Those not converted follow coordinated phosphate treatment instructions of this section.

220-31.2 FOREIGN MILITARY.

In all U.S. Navy fossil-fueled vessels chelant treatment has replaced coordinated phosphate treatment. The only ships currently using coordinated phosphate treatment are part of the Naval Sea Systems Command foreign military sales program. Coordinated phosphate and chelant treatments are the only boiler water treatments authorized by NSWCCD-SSES. If treatment chemicals or equipment for chelant or coordinated phosphate treatment are difficult to obtain, notify NSWCCD-SSES for assistance. Contact NSWCCD-SSES for authorization to use substitute equipment or chemicals. Approval of other treatments can be granted only if a successful full-scale shipboard trial, coupled with corrosion studies and sample analysis were conducted. NSWCCD-SSES can provide assistance in evaluating any boiler/feedwater chemistry control problems, such as seawater/shore water contamination, chemical hideout, carryover, etc. If a ship is experiencing problems maintaining boiler water chemical parameters, pertinent samples and logs can be submitted to NSWCCD-SSES for a complete analysis and evaluation. The point of contact for all matters regarding testing and treatment of main propulsion boilers is:

Mail: Naval Surface Warfare Center, Carderock Division
Naval Ship Systems Engineering Station, Code 622
Philadelphia, PA 19112-5083

Phone: Commercial 01-215-897-7502
DSN 443-7502

220-31.3 STEAM PLANT WATER CHEMISTRY PRINCIPLES

220-31.4 CONTROL OF FEEDWATER CONTAMINANTS.

Feedwater contaminants are controlled through the use of testing and the accomplishment of corrective actions to minimize the contaminant. Morpholine is a water treatment chemical that raises pH, thereby reducing corrosion in the condensate and deaerated feedwater lines of the pre-boiler system. In accordance with Food and Drug Administration regulations, direct contact is not permitted between morpholine treated steam and dairy products being prepared for human consumption. Pre-boiler system corrosion is caused principally by the reaction of carbon dioxide (CO_2) with the water in which it is dissolved. The carbon dioxide originates from two sources. Air containing carbon dioxide can enter at almost all points in the pre-boiler system; however, the principal source for carbon dioxide is bicarbonate ion in seawater which is released when heated in distilling plants, thereby acidifying reserve feedwater. Seawater and shore water are the major contributors of bicarbonate. Carbon dioxide reacts with water forming carbonic acid (H_2CO_3) which decreases the pH, making the water more acidic. By raising the pH of the condensate and deaerated feedwater, corrosion in these parts of the pre-boiler system is reduced. Morpholine (OC_4H_8NH), a neutralizing amine, is added to the freshwater drain collecting tank. It combines with hydrogen ions produced from the reaction of carbon dioxide in water. It also combines with some hydrogen ions present from water's ionization. As the concentration of hydrogen ions decreases, pH increases and corrosion is reduced. This reduces the amount of sludge in the boiler. The morpholine added to the condensate enters the boiler with the deaerated feedwater, is volatilized along with the steam, disperses throughout the steam plant, is condensed, and is recycled. Although the cycle is continuous, additional morpholine must be fed to the condensate to compensate for losses which occur via the air ejectors, DFT vents, and leaks. Demineralization of make up feedwater is also employed to reduce contamination levels.

220-31.5 Boiler Water Control.

The Navy employs coordinated phosphate-pH control (more simply, coordinated phosphate control) and blowdown to serve several purposes.

1. Prevent the formation of scale by maintaining a phosphate residual in alkaline water sufficient to precipitate calcium and magnesium as sludges which are less adherent than scale.
2. Prevent acid attack on boiler waterside surfaces by maintaining boiler water pH in the alkaline range.
3. Prevent caustic corrosion of boiler water by maintaining the proper relationship between pH and phosphate.
4. Prevent carryover by maintaining the dissolved and suspended materials sufficiently low.

220-31.6

Because water conditions are maintained in a manner conducive to precipitation of sludges, coordinated phosphate control is referred to as a phosphate precipitating program. Though the boiler water will accommodate some contamination, the boiler should not be considered a safe reaction vessel for the generation of sludge. Sludge is a deposit which has most of the objectionable properties of scale. The other boiler water control method, blowdown, helps to remove sludge and prevent carryover.

220-31.7 Coordinated Phosphate-pH Control.

Coordinated phosphate-pH control prevents development of water having excessive hydroxyl ions (OH^-) which lead to caustic corrosion. The treatment chemicals are trisodium phosphate, dodecahydrate (a crystalline form of trisodium phosphate), and disodium phosphate, anhydrous (a powder form of disodium phosphate). The trisodium phosphate reacts with water to form sodium hydroxide and disodium phosphate according to:

$$\underset{\text{(trisodium phosphate)}}{Na_3PO_4} + \underset{\text{(water)}}{HOH} \rightleftharpoons \underset{\text{(sodium hydroxide)}}{NaOH} + \underset{\text{(disodium phosphate)}}{Na_2HPO_4}$$

The sodium hydroxide contributes hydroxyl ions which raise pH while the disodium phosphate provides some of the needed phosphate. Sodium hydroxide and disodium phosphate could be used in the treatment to produce the same results. However, the weights of sodium hydroxide needed would be so small that weighing errors would be large. In addition, accidental overaddition of sodium hydroxide would lead to caustic corrosion.

220-31.8

Notice that the previous equation has reversing arrows. When boiler water containing the correct amount of sodium hydroxide and disodium phosphate is concentrated by heating, or evaporated to dryness, only trisodium phosphate will concentrate or remain behind. There will be no excess hydroxyl ion, called free caustic. A primary aim in coordinated phosphate control is elimination of free caustic which forms in concentrated boiler water when pH is too high (too much hydroxyl ion).

220-31.9

The amount of sodium hydroxide dissolved in boiler water converts mathematically to pH. In order to determine what pH and phosphate levels are needed to prevent formation of free caustic, it is necessary to use the calculations for aqueous equilibria as described in NSTM Chapter 220 Volume 1, Section 9. The calculations for trisodium phosphate yield the curve (line) presented in Figure 220-31-1. If 9.54 ppm of phosphate from trisodium phosphate were dissolved in water, the pH would be 10.00. If 99.17 ppm of phosphate from trisodium phosphate were dissolved in water, the pH would be 11.00. As long as boiler water phosphate and pH levels are maintained under the curve in Figure 220-31-1 free caustic cannot result. When pH rises above the curve, free caustic is present and caustic corrosion of boiler metal can result.

220-31.10

If trisodium phosphate alone were used in treatment, boiler water control would have to follow exactly along the curve. The addition of extra disodium phosphate does not detectably change the pH of the water and permits assignment of a range for boiler water control. Of significance is the fact that when added to boiler water neither trisodium phosphate nor disodium phosphate can force boiler water into the free caustic region.

220-31.11

Control limits are based on heat transfer characteristics of the boiler. Boilers whose tube heat absorption is 150,000 BTU/hr/ft^2 or less are designated Type A. These include all boilers having up to 600 psi nominal drum pressure except boilers of the AGF 3, AGF 11, AOE 1 to AOE 4, BB 61 to BB 64, CV 59, FF 1037, FF 1038, LPD 1, LPD 2, LPD 4 to LPD 10, LPD 12 to LPD 15, and LSD 32 to LSD 34 and LSD 36. These exceptions, as well as all 1,200 psi boilers, have higher heat absorption and are classed as Type B. The high heat transfer boilers have less tolerance to any chemical in the water, whether from treatment or contamination. In addition, the higher pressure boilers cannot tolerate as much conductivity as lower pressure boilers because of carryover. For these reasons, operating limits for Type B boilers are lower than for Type A boilers.

220-31.12 The Significance of Free Caustic (Corrosion and Brittle Failures).

When more hydroxyl ion is available in boiler water than will completely react with disodium phosphate to form trisodium phosphate on concentrating, the excess hydroxyl ion (free caustic) will concentrate to yield corrosive conditions in crevices, in porous deposits, at surface discontinuities (pits), and at leakage sites. The concentrated solution causes corrosion, cratering, and gouging of tube metal. Concentration of hydroxyl ion results from the thermal gradient (temperature difference) between tube metal and the film of boiler water. A 1°C (2°F) drop corresponds to a hydroxyl ion corrosive concentration of about 5 percent regardless of the amount of sodium hydroxide in bulk boiler water. A 3°C (5°F) differential can concentrate hydroxyl ion to about 10 percent. The actual concentration is also determined by the effectiveness of rinsing of boiler tube metal. Figure 220-31-2 illustrates this mechanism. Boiler water analyses show that the water is in the free caustic region above the coordinated phosphate curve with a pH of 10.65 and a phosphate of 20 ppm. The pH at the metal-deposit interface is 13. Caustic corrosion takes place at this high pH. The reactions which occur are:

a. Dissolution of the magnetite film:

2.

$$\underset{\text{(magnetite)}}{Fe_3O_4} + \underset{\text{(sodium hydroxide)}}{4NaOH} \rightarrow \underset{\text{(sodium ferrite)}}{2NaFeO_2} + \underset{\text{(sodium hypoferrite)}}{Na_2FeO_2} + \underset{\text{(water)}}{2HOH}$$

Figure 2.

b. Reaction with the base metal:

4.

$$\underset{\text{(iron)}}{Fe^{o}} + \underset{\text{(sodium hydroxide)}}{2NaOH} \rightarrow \underset{\text{(sodium hypoferrite)}}{Na_2FeO_2} + \underset{\text{(hydrogen)}}{H_2\uparrow}$$

Figure 4.

c. Reformation of magnetite and sodium hydroxide:

6.

$$\underset{\text{(sodium hypoferrite)}}{3Na_2FeO_2} + \underset{\text{(water)}}{4HOH} \rightarrow \underset{\text{(sodium hydroxide)}}{6NaOH} + \underset{\text{(magnetite)}}{Fe_3O_4} + \underset{\text{(hydrogen)}}{H_2\uparrow}$$

Figure 6.

Since sodium hypoferrite, which is a reaction product of a and b, reforms magnetite, deposits of magnetite can be found in areas of the boiler far removed from the corrosion site.

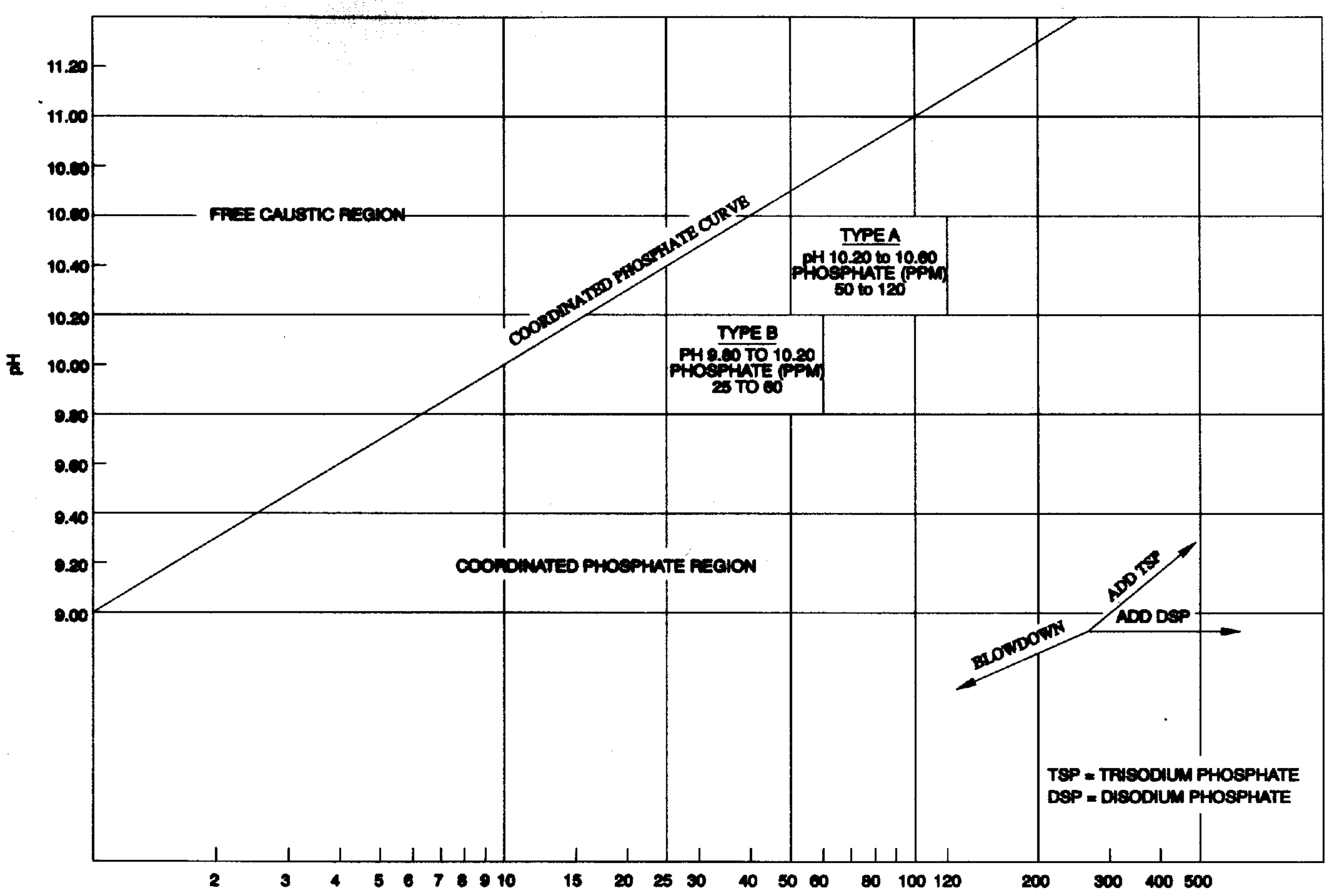


Figure 220-31-1 Coordinated Phosphate Curve

220-31.13

A prime example of caustic corrosion is evidenced by pitting and gouging in lower bends of screen tubes where deposits tend to collect. A special case of caustic corrosion is created when metal is stressed and is called caustic stress corrosion. This results in a brittle failure similar to, and as severe as, the hydrogen damage failure caused by excess acid in boiler water (paragraph 220-21.37).

220-31.14 REACTIONS IN TREATED BOILER WATER.

The behavior of treatment chemicals in general, and under various contaminant conditions is described in the following paragraphs.

220-31.15 Precipitation Reactions (Sludge Formation).

The alkaline pH level in boiler water serves to minimize boiler metal corrosion and also provides hydroxyl ions (OH^-) needed to react with the magnesium that would otherwise turn neutral water acidic. The reaction is:

$$\underset{\text{(magnesium ion)}}{Mg^{2+}} + \underset{\text{(hydroxyl ion)}}{2OH^{-}} \rightarrow \underset{\text{(magnesium hydroxide)}}{Mg(OH)_2\downarrow}$$

The magnesium hydroxide forms a sludge as long as the water remains alkaline. Both the sodium hydroxide and disodium phosphate in the water react with calcium and magnesium to form various phosphate sludges as follows:

$$\underset{\text{(calcium chloride)}}{5CaCl_2} + \underset{\text{(disodium phosphate)}}{3Na_2HPO_4} + \underset{\text{(sodium hydroxide)}}{4NaOH} \rightarrow \underset{\text{(hydroxyapatite)}}{Ca_5(OH)(PO_4)_3\downarrow} + \underset{\text{(sodium chloride)}}{10NaCl} + \underset{\text{(water)}}{3HOH}$$

Other reactions are given in Section 21.

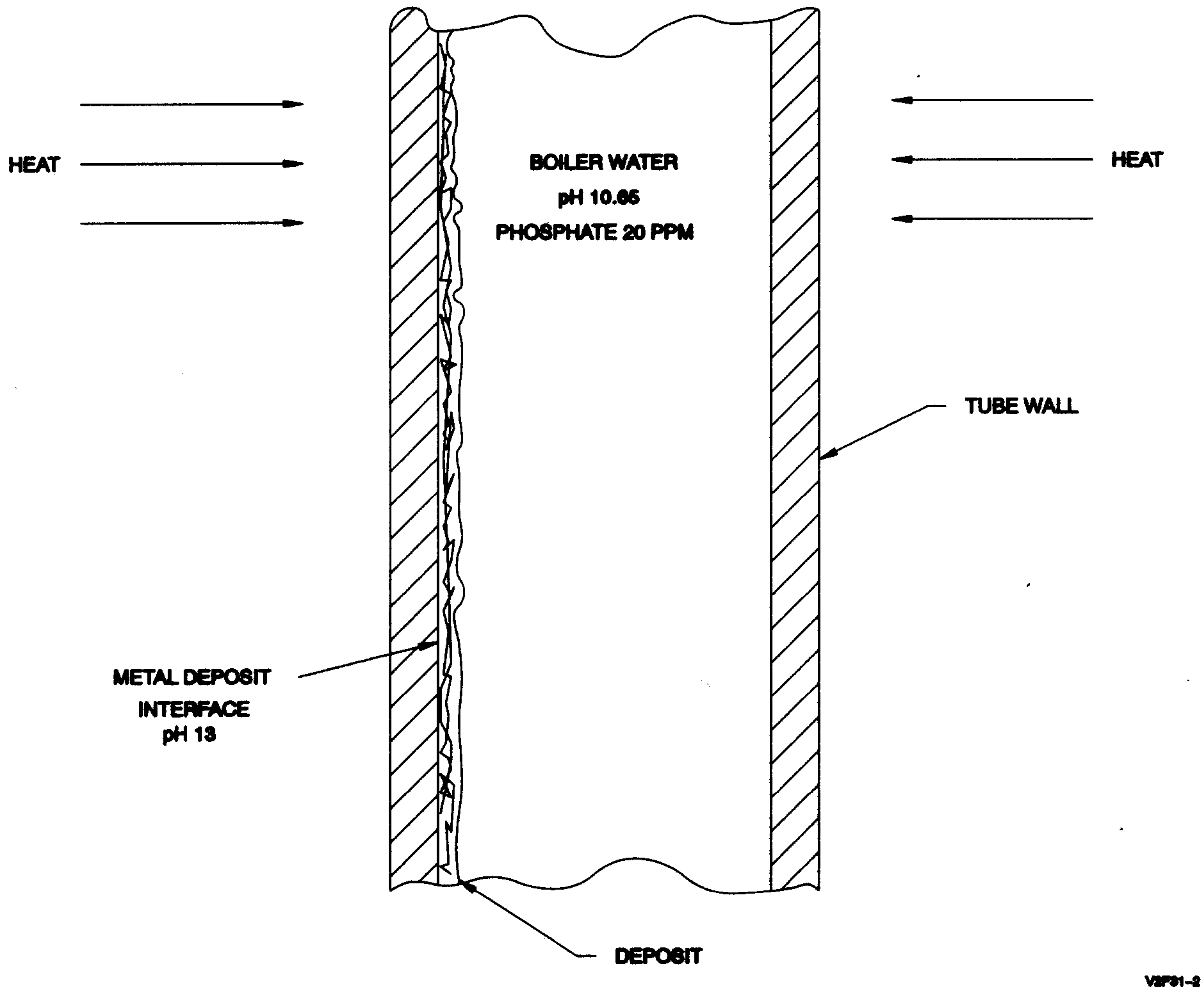


Figure 220-31-2 Caustic Concentration Mechanism

220-31.16 Effect of Seawater on Boiler Water Chemicals.

When seawater enters boiler water, it carries with it four indicators: magnesium, calcium, chloride, and conductivity. Because of the large amount of magnesium, the chemical reaction causes pH to drop. Both magnesium and calcium will cause phosphate to decrease because of the formation of sludge containing phosphate. Chloride and conductivity will increase. The pH and phosphate must always be kept under the coordinated phosphate curve and within specified limits because of the damage that will result if either pH becomes acidic or phosphate disappears.

220-31.17

As a matter of interest, addition of salt alone, sodium chloride, will increase chloride and conductivity but will not affect pH or phosphate. It is not sodium chloride nor chloride per se which causes scale formation or acid attack.

220-31.18 Effect of Shore Water on Boiler Water Chemicals.

Shore water has one major indicator, calcium. The relatively large amount of calcium in shore water in comparison to magnesium causes phosphate to decrease. The pH will increase. Conductivity will slowly increase.

Chloride may not change. Since shore water depletes phosphate and increases pH, boiler water control parameters will be forced into the free caustic range. Again, the pH and phosphate must always be kept under the coordinated phosphate curve and within specified limits to prevent scale formation and caustic corrosion.

220-31.19 Chemical Hideout.

The phenomenon of chemical hideout disrupts control of boiler water treatment. Chemical hideout is usually evidenced by a diminishing level of phosphate as boiler steaming rate increases. Phosphate returns when the steaming rate decreases or when the boiler is secured. The reasons for its occurrence are not well defined, but two likely mechanisms have considerable data to support them. Both are probably correct.

220-31.20

One mechanism shows that circumstances must allow concentration of chemicals. The other shows that reaction with the magnetite protective layer occurs.

220-31.21

If tube surfaces are smooth and free of deposits, boiler water circulates freely and is effective in continuously washing tube metal. Porous deposits, crevices, pits and leakage sites interfere with circulation creating areas conducive to concentration of boiler water. All of the normally soluble chemicals concentrate. If the interference is severe, localized dry-out of boiler water treatment chemicals and contaminants can occur. Sodium chloride is more soluble in high-temperature water than trisodium phosphate which is more soluble than disodium phosphate. When such localized concentration of boiler water is occurring, pH, phosphate, and conductivity decrease. A decrease in chloride may or may not be detected. As heat input to the boiler tubes increases, the concentrating effect at the metal increases. As heat transfer rate decreases, the chemicals return to the bulk boiler water.

220-31.22

Phosphates also react directly with magnetite (Fe_3O_4) to form a solid sodium iron phosphate compound whose exact chemical structure is unknown. This is a high-temperature reaction and the compound decomposes when temperatures are reduced. If reaction with magnetite is occurring, pH increases when phosphate decreases, and vice versa.

220-31.23

Virtually all instances of chemical hideout in naval boilers are reported after the following events have occurred:

1. Acid cleaning.
2. EDTA cleaning.
3. A contamination incident.
4. Initiation of morpholine.

The events can all cause disruption of magnetite or generation of deposits in the boiler and the appearance of hideout. Mechanical cleaning (via water-jet) alleviates the condition when caused by soft deposits. If contamination has caused hard deposits, only acid cleaning will remove them. Hard deposits represent a hazard to boiler operation and in themselves cause hideout.

220-31.24

The reason for development of hideout soon after acid cleaning is not clear, but either or both of the previously described mechanisms may be at work when sensitized metal surfaces and soft deposits are present. Refer to paragraphs 220-31.134 and 220-31.138 for further discussion of hideout.

220-31.25 BLOWDOWN.

Blowdown provides control of accumulated boiler water solids both suspended and dissolved. Both surface and bottom blowdowns are employed.

220-31.26 IDLE BOILER MAINTENANCE.

As described in Section 21, the prime consideration of idle boiler layup is the prevention of oxygen corrosion of the boiler metal.

220-31.27 FEEDWATER REQUIREMENTS.

The feedwater requirements of Section 22 are generally applicable except as noted here. Table 220-31-1 provides a summary of feedwater requirements. Refer to Section 22 for additional guidance on specific feed system component limits as well as shore source steam and feedwater quality requirements.

220-31.28 Morpholine Condensate Treatment.

A number of ships are equipped with morpholine condensate treatment systems that utilize a water solution of 40 percent morpholine as the treatment chemical. Detailed operating and maintenance instructions for morpholine condensate treatment systems are contained in NAVSEA S9255-AE-MMO-010/MCTS. Figure 220-31-3 shows the relationship of units in the morpholine condensate treatment system. Morpholine is continuously gravity fed to the freshwater drain collecting tank to obtain a pH range of 8.60 to 9.00 in the steam drain lines, condensate, and deaerated feedwater. Sampling is performed at the DFT sample cooler outlet. The feedwater pH is determined by use of a pH test (paragraph 220-31.183).

WARNING

Morpholine is an alkaline chemical which causes burns. Use care in handling. If morpholine contacts skin, flush with cold water. If morpholine or its solutions enter the eyes, flush with cold water for 15 minutes and seek immediate medical attention. Wear goggles, face shield, apron, and plastic or rubber gloves when handling morpholine.

220-31.29

The level of 40 percent morpholine solution in the morpholine treatment tank must be checked periodically. Whenever the solution level drops to less than 10 gallons, add morpholine solution to bring the solution level in the tank to 20 gallons.

220-31.30

The addition of morpholine increases the conductivity of water. Since salinity indicators measure conductivity, not chloride, salinity indicator readings will rise although the actual chloride content is not increased by the addition of morpholine. The chemical chloride limit for all condensate and feedwater is 0.02 epm regardless of whether the condensate is treated with morpholine. Salinity indicator readings over 0.04 epm or 6 µhmo/cm indicate contamination or morpholine overtreatment. Chemical tests for chloride, hardness, and feedwater pH shall be conducted when this limit is exceeded and appropriate corrective action shall be taken. The chemical chloride limit can be exceeded without raising the salinity readings above the 0.04 epm or 6 µhmo/cm limit. Therefore, ships using morpholine treatment shall conduct chemical tests as appropriate whenever salinity indicators show a significant increase above normal, even though the salinity indicator readings are within limits. Test for chloride, then hardness, then feedwater pH, and take corrective action based on results of chemical analysis. When performing the salinity indicator comparison tests, if the chemical chloride test result is lower than the salinity indicator reading by more than 0.02 and the hardness is 0.02 epm or less, check the feedwater pH. If the feedwater pH is 9 or less, check the indicator for malfunction. If the pH is greater than 9, the indicator is functioning satisfactorily.

NOTE

Main condensate and distilling plant salinity and conductivity indicator alarms and dump valves shall be set as close to the above limits as installed hardware permits. Replacement or modification of installed hardware is not authorized or required by this chapter. Updating of these systems is only approved by ship alteration as authorized by the Type Commander and NAVSEA.

Table 220-31-1 COORDINATED PHOSPHATE PROPLUSION BOILER FEEDWATER, REQUIREMENTS SUMMARY

	Maximum Limit			
Source	**Conductivity Indicator µmho/cm max**	**Salinity Indicator epm**	**Chemical Chloride epm**	**Chemical Hardness epm**
Distillate	10.0	0.065	0.07	----
Distiller Air Ejector Drains	10.0	0.065	0.02	----
Reserve Feedwater/Makeup Feedwater	15.0	0.100	0.10	0.10
Demineralized Makeup Feedwater	1.0	----	----	----
Deaerated Feedwater, Condensate, and Drains without Morpholine	3.0	0.020	0.02	0.02
Deaerated Feedwater, Condensate, and Drains with Morpholine	6.0	0.040	0.02	0.02
			Dissolved Oxygen ppb	**Morpholine Treatment pH (Range)**
Deaerated Feedwater			15	8.6-9.0

COORDINATED PHOSPHATE PROPULSION BOILER FEEDWATER,
REQUIREMENTS SUMMARY (Cont'd)

Source	**Test Frequency**
All distillate, condensate, and feedwater monitored by salinity indicators.	Perform daily comparison test on all salinity indicators that can be sampled (except distiller air ejector drains).
	Monitor indicators whenever system component is operating.
	When indicator is malfunctioning, test the water that is monitored by the affected indicator for chloride every 4 hours or test boiler water every 4 hours.
Distiller air ejector drains	Test for chloride daily.
	When indicator malfunctions or indicates an out of limits condition, test for chloride every 4 hours. Drains may be used based on chemical chloride test.
Reserve and makeup feedwater	Test all unused feedwater tanks daily for chloride and hardness while steaming.
	For cold plant start-up, test first reserve feedwater tank for chloride within 30 minutes prior to use.
	Monitor salinity or conductivity indicator or demineralizer inlet cell as soon as feed tank is placed on makeup.
	When indicator is faulty, test each reserve feedwater tank for chloride within 30 minutes prior to use.
	When demineralizer is in use, monitor outlet conductivity cell.
Deaerated feedwater	Dissolved Oxygen: Prior to feeding boiler. 2-3 hours after boiler is on-line. Daily.
	pH (Morpholine treatment only): 60-90 minutes after start of treatment. Every 12 hours.
Service steam (low pressure)	Test for chloride and hardness prior to aligning to FWDCT.
	In-port test for chloride and hardness daily when aligned to FWDCT.

Note

Salinity indicator alarm and dump valves shall be set as close to the above limits as installed hardware permits. Replacement or modification of installed hardware is not authorized or required by this chapter. Updating of these systems is only approved by ship alteration as authorized by the Type Commander and NSWCCD.

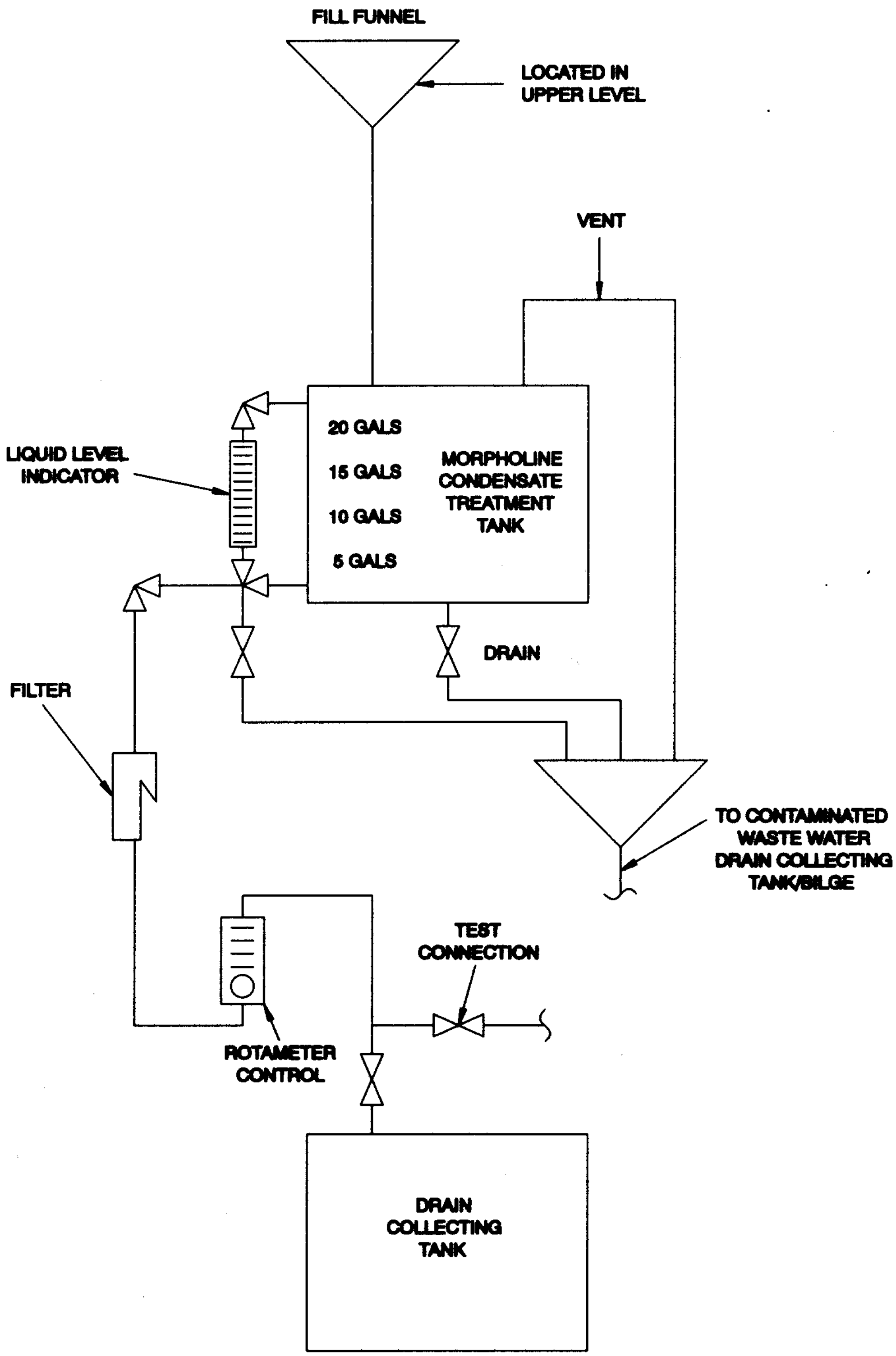


Figure 220-31-3 Morpholine Condensate Treatment System

220-31.31

All ships having the morpholine system installed (Figure 220-31-3) shall operate it in a continuous treatment mode. Continuous injection of morpholine shall be performed only when the condensate/feedwater system is on-line. The amount of morpholine injected into the freshwater drain tank is controlled by adjusting the rotameter setting. Aircraft carriers have a flowrater and float that are different from other surface ships in order to permit a higher flow rate of morpholine into the condensate system. The need for a higher flow rate results from a relatively higher makeup rate aboard aircraft carriers. Ships which have both morpholine condensate treatment and reserve feedwater demineralizers installed should ensure proper DFT level control calibration to prevent unnecessary dumping of morpholine-treated condensate to the reserve feed systems. This results in depletion of both morpholine and demineralizer resin, and hot condensate dumped back to the reserve feed tank can cause melting of demineralizer resin.

220-31.32

Initiation of the morpholine treatment sometimes causes a sludge buildup to occur in boilers. This results from the scouring effect of the treatment whereby loosely adhering corrosion products on the surfaces of the preboiler system are flaked off into the feedwater and are carried into the boiler. Following initial installation and use of the morpholine treatment system, more frequent blowdown is required. It is required that two nominal 10 percent surface blowdowns be performed daily and bottom blowdown be performed at least every 72 steaming hours. If at all possible, the bottom blowdown should be performed every 48 steaming hours. The DFT and boiler watersides shall be inspected for the presence of sludge at intervals of 300 steaming hours. Visible sludge must be removed. Waterside inspections shall be performed every 300 hours until the sludge buildup has ceased.

220-31.33 MORPHOLINE TREATMENT.

The treatment procedure is:

1. As soon as the boiler is on-line, the steam drains are certified as acceptable, and the freshwater drain collecting tank is aligned to the main condenser or the condensate system, open the morpholine solution shutoff valve.

2. Adjust the rotameter to obtain a flow indication equal to the setting logged during the previous steaming period. For first time use of new installations, initially set flowrater to the 4 setting.

3. Sixty to ninety minutes after start of treatment, and at least every 12 hours while the system is in operation, obtain a feedwater sample from the DFT and test the sample for pH (paragraph 220-31.183).

4. If test results show a high pH (above 9.00) or low pH (below 8.60) level over a 24-hour period, adjust the rotameter float by ±10 percent (one unit on rotameter) accordingly until the pH level is consistently within the allowable range (8.60 to 9.00). Increase morpholine flow to raise condensate pH or decrease morpholine flow to decrease condensate pH. Allow 24 hours before making any additional adjustments.

220-31.34

To secure, close the rotameter needle valve and morpholine solution discharge shutoff valve just before securing the feedwater system (including drills).

220-31.35 REQUIREMENTS FOR PROPULSION BOILER WATER FOR SHIPS USING COORDINATED PHOSPHATE BOILER WATER TREATMENT

220-31.36

The chemical treatment used in main propulsion boiler water is designed so that pH and phosphate are maintained under the coordinated phosphate curve (paragraphs 220-31.7 through 220-31.13) and within specified limits. Because of differences in heat transfer rates, boiler water pH, phosphate, and conductivity limits for Type A boilers are different from Type B boilers. Refer to paragraph 220-31.1. The chloride limit is the same since it is based on feedwater/condensate contamination limits. Although limits are different, all test and treatment procedures are the same. The boiler water limits are given in Table 220-31-2.

Table 220-31-2 BOILER WATER CONTROL LIMITS

Type A		Type B	
pH	10.20 - 10.60	pH	9.80 - 10.20
Phosphate	50 - 120 ppm	Phosphate	25 - 60 ppm
Conductivity	600 µmho/cm max	Conductivity	400 µmho/cm max
Chloride	1.0 epm max	Chloride	1.0 epm max
Note For the first and second after on the line (AOL) sample, the lower limit for pH is 9.00 and phosphate is 10 ppm.			

220-31.37

Two treatment chemicals, trisodium phosphate and disodium phosphate, are normally used to control pH and phosphate. Trisodium phosphate raises both pH and phosphate while disodium phosphate raises the phosphate level without significantly affecting the pH. Caustic soda may be used under casualty control circumstances (paragraphs 220-31.108.5 and 220-31.108.7) when only pH adjustment is needed and phosphate is above the upper limit. Figure 220-31-4 shows the positions of boiler water control parameters under the curve for all propulsion boilers.

220-31.38

The pH limits provide an alkaline boiler water which is necessary for reaction of calcium and magnesium with the phosphate in the water to form sludge. Alkaline boiler water also reduces corrosion of tube metal. The phosphate in the alkaline water reacts with calcium and magnesium contaminants and provides protection against formation of acid or excess alkali. Under normal conditions (contamination not occurring), the boiler water chloride level should not exceed 1.00 epm. The conductivity limit is based on the total conductivity contributed by pH, phosphate, and contamination. Table 220-31-3 shows the theoretical conductivity of various species measured in boiler water. Theoretical conductivity is calculated daily for a steaming boiler. Under normal conditions the measured conductivity will not differ from the theoretical conductivity by more than 30 percent. A difference greater than 30 percent may indicate contamination from other than a seawater source, a faulty meter or one or more tests being in error. If measured conductivity differs from theoretical conductivity by more than 30 percent for the first samples taken following hydrazine/morpholine layup, take no action unless the condition is still present after 24 hours of steaming. If measured conductivity differs from theoretical conductivity by more than 30 percent for a routine sample:

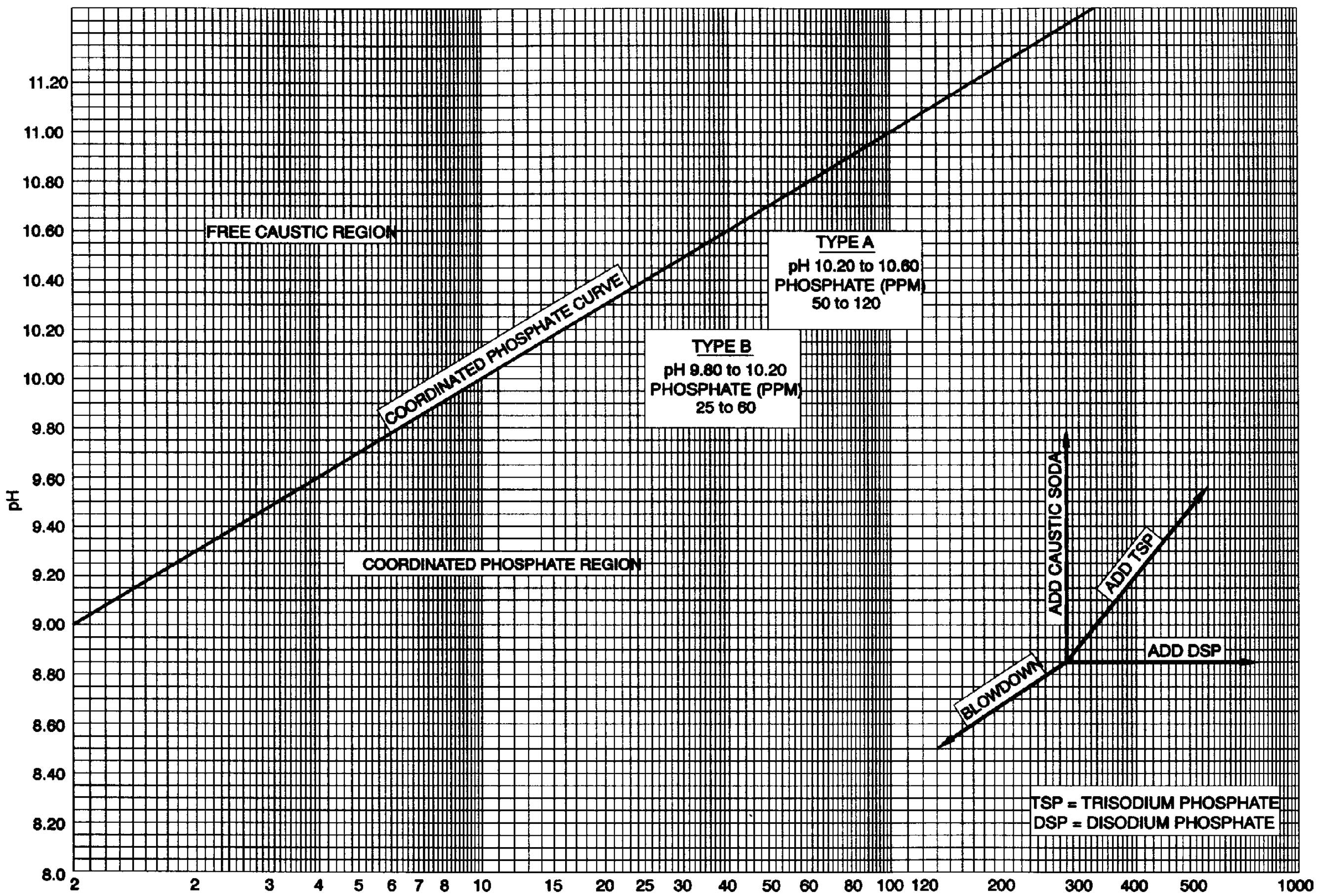


Figure 220-31-4 Coordinated Phosphate Control Curve

a. Resample and test to verify results and correct analysis methods.

b. If the second analysis indicates more than a 30 percent difference between measured and theoretical conductivity, conduct standardization and calibration procedures on all equipment and reagent. Resample and test.

c. If the third analysis indicates more than a 30 percent difference between measured and theoretical conductivity, contamination other than a seawater source is occurring. The most probable contamination sources are shore water, demineralizer resin and morpholine. If the source of contamination cannot be identified, assistance can be requested from the Naval Surface Warfare Center Carderock Division.

Table 220-31-3 THEORETICAL CONDUCTIVITY OF BOILER WATER

A. pH contributes to total boiler water conductivity:

Table 220-31-3 THEORETICAL CONDUCTIVITY OF BOILER WATER -

Continued

pH	Conductivity (µmho/cm)	pH	Conductivity (µmho/cm)
9.00	2.5	10.00	25
9.05	2.8	10.05	28
9.10	3.1	10.10	31
9.15	3.5	10.15	35
9.20	3.9	10.20	39
9.25	4.4	10.25	44
9.30	4.9	10.30	50
9.35	5.5	10.35	56
9.40	6.2	10.40	62
9.45	7.0	10.45	70
9.50	7.8	10.50	78
9.55	8.8	10.55	88
9.60	9.9	10.60	99
9.65	11	10.65	111
9.70	12	10.70	124
9.75	14	10.75	140
9.80	16	10.80	157
9.85	18	10.85	176
9.90	20	10.90	197
9.95	22	10.95	221
B. PHOSPHATE: For each 1 ppm phosphate, boiler water conductivity will increase by 2.25 µmho/cm.			
C. CHLORIDE: For each 1 epm chloride (from seawater), boiler water conductivity will increase by 145 µmho/cm.			
If the chloride results from shore water, the conductivity can be predicted only if an analysis of the shore water is available.			

THEORETICAL CONDUCTIVITY OF BOILER WATER (Cont'd)

D. EXAMPLES		
Boiler Water Results	**Calculation**	**Theoretical Conductivity (µmho/cm)**
pH 10.20	Conductivity from table	39
Phosphate 60 ppm	60 ppm x 2.25 µmho/cm/ppm	135
Chloride 1.00 epm	1.00 epm x 145.0 µmho/cm/epm	145
		Total 319
pH 10.60	Conductivity from table	99
Phosphate 120 ppm	120 ppm x 2.25 µmho/cm/ppm	270
Chloride 1.00 epm	1.00 epm x 145.0 µmho/cm/epm	145
		Total 514

Note

When pH increases by one, conductivity increases by a factor of 10. This relationship can be used for estimating conductivity values for pH greater than those listed in the table.

220-31.39

Two aims are paramount in the Navy COPHOS boiler water treatment. These are:

1. Maintain boiler water under the curve in the coordinated phosphate region.
2. Maintain boiler water within limits.

220-31.40

The small arrows in the right-hand corner of Figure 220-31-4 serve to indicate the approximate direction that treatment actions will cause boiler water control parameters to move when chemical addition or blowdown is applied. If trisodium phosphate is added, pH and phosphate will increase in a direction that slowly approaches the curve. Addition of disodium phosphate moves boiler water conditions to the right. Addition of caustic soda causes an increase in pH only. Blowdown causes pH and phosphate to decrease in a direction parallel to the curve. In all but a very few instances, the chemical treatment dosage tables will compensate for and correct boiler water conditions moving pH and phosphate near the upper limits for the boiler water. Since pH and phosphate control limits are higher for Type A than for Type B boilers, dosage tables are different; however, the operational requirements and test procedures are the same. A log of the boiler water conditions shall be maintained in accordance with paragraph 220-31.222.

220-31.41 INITIAL TREATMENT.

It is good engineering practice to use the hottest feedwater available to fill a boiler in preparation for light-off; however, the following waters are acceptable when freshly filling:

1. Hot deaerated feedwater.
2. Cold feedwater, meeting the requirements of paragraphs 220-31.18 or 220-31.19 if the feedwater is from a shore source, or paragraph 220-22.11 if from the ship's evaporators. Cold feedwater should not be used unless a ship is unable to operate the DFT.
3. Hydrazine/morpholine treated feedwater used for layup.

220-31.42

The following waters may not be used to fill a boiler in preparation for light-off:

1. Raw shore water.
2. Water used to hydrostatically test a boiler after an acid cleaning and any other water that contains sodium nitrite.
3. Feedwater that does not meet the requirements of paragraph 220-22.22 for shore source feedwater or paragraph 220-22.11 for reserve feedwater from the ship's evaporators.

220-31.43

All the waters listed in paragraph 220-31.42 shall be dumped. Flushing of the watersides, steamsides, or feed tanks that contained the water is required. If sodium nitrite was not properly dissolved in the water or drained from the boiler, it can cause boiler water control problems. See paragraph 220-31.162 for casualty control procedures.

220-31.44

The boiler is normally filled to the bottom of the direct reading gauge glass with deaerated feedwater (if available). Feedwater, used in a hydrostatic test, or hydrazine/morpholine treated feedwater used for layup, must be drained to the bottom of the direct reading gauge glass. Treatment chemicals are then added to bring boiler water conditions to the upper limits of the appropriate boiler water treatment. The necessary amount of treatment is weighed, dissolved in feedwater, and injected into the boiler. All propulsion boilers are equipped with a chemical injection system. The injection procedure, including a schematic of the system, is shown in Figure 220-22-4. When an injection system is used, care must be exercised to keep the amount of air introduced into the boiler to a minimum. The tank is overfilled slightly to bleed air out of it. Overfilling must be minimized to avoid the loss of treatment chemicals. In addition, the tank must be on-line for at least 10 minutes to ensure that all of the treatment is flushed into the boiler. Check boiler water level to verify that chemicals are added to the boiler. It is permissible to inject chemicals at any time during the boiler filling process. On some ships it may be preferable to add the chemicals before filling the boiler, particularly if low test results for phosphate, pH or alkalinity have been previously encountered in the after-on-line sample(s). Upon completion of chemical addition, finish filling the boiler to the light-off level or, if the boiler has been overfilled, drain until the proper water level is reached. A boiler water sample, obtained from a freshly filled, chemically treated boiler prior to light-off, is not required because the sample is not representative and is therefore meaningless. Circulation of boiler water to distribute the chemicals is prohibited because boiler metal damage through oxygen attack may result. The freshly filled and treated boiler should be lit off immediately, but not later than 24 hours after being filled. Preferably, the boiler should not be filled unless it is expected that it will be lit off within 24 hours. If the boiler cannot be lit off within 24 hours after filling, it shall be dumped and placed under layup as prescribed in Section 22 and in NSTM Chapter 221, Boilers. A boiler is considered to be steaming (on-line) for boiler water chemistry purposes from the time auxiliary or main steam stops are open until fires are secured. For calculation of steaming hours, a boiler is considered to be steaming when the fires are lit.

NOTE

Figure 220-22-4 is based on NAVSEA STD DWG 803-1385375. Ships that do not have the configuration specified in this figure/drawing are being upgraded by ship alteration. Figure 220-22-4 may be marked up to reflect individual ship configurations and used for chemical injection until the applicable ship alteration has been accomplished.

220-31.45 STEAMING BOILERS.

Boiler water in a steaming boiler shall be maintained in accordance with the requirements for that particular type of boiler. Boiler water samples shall be obtained from a steaming boiler in accordance with the following requirements:

1. Within 1/2 hour after the boiler has been placed on-line (auxiliary or main steam stops open), and then two additional samples 60 to 75 minutes apart. (See NOTE)
2. As often as required to maintain a boiler within limits but at least every 8 hours (maximum 8 hours between samples).
3. Within 1 hour before commencing surface and bottom blowdowns. (See NOTE)
4. Thirty to forty-five minutes after surface and bottom blowdowns are completed.
5. Sixty to ninety minutes after chemical treatment.
6. Within 90 minutes prior to securing the boiler. (See NOTE)

NOTE

The lower limit for pH is reduced to 9.00 and for phosphate to 10 ppm for the after on line samples to allow boiler water to reach equilibrium. Base treatment action on the the third after on line sample, unless the pH or phosphate are less than these reduced limits or contamination occurs. If pH is less than 9.00 or phosphate less than 10 ppm, add treatment chemicals using the normal dosage tables. If contamination occurs, treat the boiler in accordance with casualty control procedures. If it becomes necessary to secure the boiler, treat based on the last sample taken.

NOTE

When a boiler is secured as a result of a non-chemistry related casualty, control of the casualty takes precedence over the requirements of paragraphs 220-31.45.3 and 220-31.45.6; in these cases the prior to blowdown and prior to securing samples are not required. Only one after on-line sample is required after restoration of a non-chemistry casualty unless:

a. The boiler was secured for more than two hours.

b. The boiler was treated while it was secured.

c. The boiler was blown down while secured.

220-31.46

When chemical treatment is needed as indicated by boiler water test results, treatment injection shall be initiated within 1 hour after sampling.

220-31.47

The time limitations specified in paragraphs 220-31.45 and 220-31.46 above apply to normal steaming. Under casualty control circumstances, rapid response is needed in order to prevent boiler damage. Refer to paragraphs 220-31.94 through 220-31.116 for requirements.

220-31.48 SAMPLING DURING CASUALTY CONTROL DRILLS.

The sampling requirements during casualty control drills are the same as those for the actual casualty. It is recommended that affected boilers be tested and treated before initiating the drill session to allow time to take a follow up sample before starting the drill. It is also recommended that salinity indicators be continually monitored during each evolution. The boiler shall be sampled within the 8-hour sampling frequency regardless of how long the drill continues. If an actual chemistry casualty occurs during the drill, the drill shall be terminated and the chemistry casualty shall be controlled.

220-31.49 WATER TREATMENT PRIOR TO SECURING.

Within 90 minutes prior to securing, sample the boiler water. Test the sample and treat the boiler if required. After completing chemical injection, either secure within 90 minutes of the prior to securing sample (use the sample taken one hour prior to blowdown as both the after chemical addition and prior to blowdown sample) or continue steaming and take the after chemical addition sample 60 to 90 minutes after chemical addition. If treatment is not required, either secure within 90 minutes of the prior to securing sample or continue steaming taking another prior to securing sample within 90 minutes of securing.

220-31.50 SURFACE BLOWDOWN.

Surface blowdown provides the normal control of boiler water conductivity, chemical overtreatment, and nondetergent lubricating oil. In following the procedures of paragraph 220-31.51, an approximate 5-percent surface blowdown will be obtained; however, there is no requirement for a percentage surface blowdown. Surface blowdown shall be performed on a steaming boiler as necessary to maintain boiler water within limits. There is no interval specified for performance of surface blowdown since the need for the action is dictated by the chemical test results of the boiler water. It is required that the percentage blowdown be recorded in the boiler water treatment log since it gives an indication of procedural or water treatment problems. When a secured boiler under a steam blanket wet layup is run down to reduce water level, no testing prior to or after the rundown is required; however, the action should be noted on the boiler water log.

220-31.51 SURFACE BLOWDOWN PROCEDURE.

When conducting a surface blow on a steaming boiler, do not permit steam drum water level to drop below the surface blow takeoff or drop out of sight in the boiler water gauge. Do not permit superheater outlet temperature to rise above the maximum limit. Maintain a steady feedwater rate and do not change this rate during blowdown. Ensure that the boiler gravity drain hose valve connection is closed and capped during blowdown. (See Figure 220-22-5 for a typical arrangement.) Blowdown piping materials are specified in **NSTM Chapter 221** . Surface blowdown is conducted in the following manner:

1. Obtain permission to conduct blowdown.
2. Prepare the blowdown system by first opening the overboard discharge valve(s) and then the guarding valve(s).
3. Nonpressure-fired boilers: By manual or remote manual feedwater control, establish the boiler water level at 3 inches above the surface blow take-off pipe. Pressure-fired boilers: Switch the feedwater to manual or remote manual control and maintain a steady feedwater rate. Do not raise the boiler water level above normal.
4. Wait 4 to 5 minutes and then open the surface blow valve. Do not throttle. Maintain continuous observation of the boiler water level during blowdown.
5. Nonpressure-fired boilers: Close the surface blow valve quickly when the water level in the steam drum drops to the surface blow pipe. Pressure-fired boilers: Close the surface blow valve quickly when the water level in the steam drum drops 3 inches below normal.
6. Repeat steps 3 through 5 as required to correct observed conditions. Refer to paragraphs 220-31.65 and 220-31.78 for guidance specific to Type A and Type B boilers.
7. After completing the surface blow, return water level to normal, close the guarding valve(s) and the overboard discharge valve(s), in that order. Open the drain valve to the bilge to ensure tight seating of the surface blow valve. Close the valve when pressure is relieved. Monel-type guarding and overboard discharge valves require a second securing; therefore, retorque the valves 15 minutes after the boiler blow is completed and the system is secured. The 15-minute cool down period and retorque of monel valves are required to prevent leakage.

NOTE

Pressure-fired boilers: If oil or scum is definitely present in the steam drum, procedures are the same except for water level. To remove oil or scum, surface blowdown is conducted by lowering water level to minus 4 inches while steaming, then opening the surface blow valve, and blowing down to minus 6 inches.

220-31.52 BOTTOM BLOWDOWN.

A bottom blowdown removes sludge from the waterdrum and all installed bottom waterwall headers. Successful bottom blowdown will result in a reduction in steam drum water level. If a reduction in boiler water level is not observed, bottom blowdown valves may be plugged. There is no numerical requirement for a percentage bottom blowdown. Bottom blowdown shall be performed whenever the boiler is secured (unless it is to be lighted off again within 2 hours). The boiler shall be secured and given a bottom blowdown within 168 steaming hours of the last bottom blowdown. Do not bottom blow a steaming boiler. Repetitive blowdowns, either surface or bottom, may be accomplished whenever needed to reduce contamination levels in the boiler, as long as deaerated feedwater is available. The interval between bottom blowdowns shall not exceed 72 hours when consumption of treatment chemicals increases by 50 percent or more above normal.

220-31.53

When visual inspection of the drums and headers indicates excessive sludge buildup, or when visible solids or discoloration are observed in boiler water samples, the blowdown frequency should be increased. Blowdown should also be increased after overhaul or waterside cleaning to reduce dirt, debris and suspended solids, and any time visible solids are observed in the sample.

220-31.54 BOTTOM BLOWDOWN PROCEDURE.

See Figure 220-22-7 for a typical blowdown piping arrangement. Blowdown piping materials are specified in **NSTM Chapter 221** . Conduct bottom blowdown as follows:

1. Sample, test, and chemically treat the boiler water within 90 minutes prior to securing.
2. Secure the boiler and let it stand for at least 1 hour, but no more than 24 hours.
3. Obtain permission to conduct blowdown. Never attempt to bottom blow with less than 100 psi pressure on the boiler.
4. Sample and test the boiler water within 1 hour prior to blowdown.
5. Raise the steam drum water to plus 6 inches.
6. Prepare the blowdown system by opening the overboard discharge valve(s) and the guarding valve(s), in that order.

7a. (For nonpressure-fired boilers.) Quickly open the water drum blow valve until 2 inches of water have been blown out and then quickly close the valve. The water drum blowdown should result in approximately a 4-inch drop in water level. Repeat blowdown at each header valve, except allow the water level to drop only 1 to 1-1/2 inches before closing each valve.

7b. (For pressure-fired boilers.) Quickly open the convection header portside blow valve until 1 to 1-1/2 inches of water have been blown out and then quickly close the valve. Repeat procedure for starboard side header and port and starboard downcomer blow valves. Each blow should result in approximately a 2 to 3 inch drop in water level.

8. Do not let the water level drop out of sight in the boiler water level gauge. If hot deaerated feedwater is not available, discontinue the blowdown and note the blowdown points missed in the boiler water log.

NOTE

Ships that repeatedly have incomplete bottom blowdowns must change the order of header blowdown from blowdown to blowdown to ensure adequate blowdown of all headers.

9. On completion of blowdown close the guarding valve(s) and the overboard discharge valve(s) in that order. Open the drain valve to the bilge to ensure tight seating. Close the valve when pressure is relieved. Monel-type guarding and overboard discharge valves require a second shutting after a 15-minute cool down period to prevent leakage. If hot deaerated feedwater is available, raise the steam drum water level to steaming level.

10. Sample and test the boiler water 30 to 45 minutes after the completion of the blowdown.

220-31.55 PERCENT BLOWDOWN.

The percent surface blowdown is determined by using the formula. Round to the nearest whole number (i.e., 10.4% rounds to 10%, 10.5% rounds to 11%).

% blowdown = $100(C_B - C_A)/C_B$ where:

C_B = conductivity before blowdown

C_A = conductivity after blowdown

NOTE

There is no requirement for calculation of percent bottom blowdown.

220-31.56 IDLE BOILER WATER.

Since atmospheric oxygen can be drawn into an idle boiler under wet layup, it is important that the proper procedures for maintaining a positive pressure on an idle boiler be used. Refer to Section 22 and **NSTM Chapter 221** for layup procedures. Within 1 hour prior to bottom blowdown and 30 to 45 minutes after completing the bottom blowdown operation, a boiler water sample shall be obtained and tested for pH, phosphate, conductivity, and chloride. It is not necessary to chemically treat after bottom blowdown. No further chemical testing or treatment is required for a boiler under wet layup until within 1 hour prior to light-off for the following reasons:

1. The boiler water conditions will not normally change while the boiler is under wet layup except in the case of a steam blanket where gradual dilution will take place. A boiler maintained under hydrostatic pressure may exhibit some minor dilution.

2. As long as the boiler water has been treated, waterside deposits will not form since the boiler is not being fired.

3. A water sample taken from an idle boiler cannot be assumed to be representative of the actual boiler water conditions.

CAUTION

If the boiler was secured because of a chemical casualty, treatment may be required. Refer to paragraphs 220-31.94 through 220-31.116 for details.

4. Addition of treatment chemicals to a cold boiler incurs a risk of dissolved oxygen contamination.

220-31.57

Within 1 hour preceding boiler light-off, sample and test the idle boiler water. This sample is not required for a freshly filled and treated boiler, or when the boiler has been secured for two hours or less due to a non-chemistry related casualty. Based on the test results, appropriate action shall be determined in accordance with the following requirements:

1. Do not chemically treat if test results indicate all of the following:
   a. pH is 9.00 or greater.
   b. Phosphate is 10 ppm or greater.
   c. pH and phosphate are in the coordinated phosphate region of Figure 220-31-4.
   d. Conductivity is below limit (600 µmho/cm for Type A and 400 µmho/cm for Type B).
   e. Chloride is below 1.0 epm.

NOTE

Boiler water results within the above limits are within limits for the secured boiler and need not be circled on the boiler water log.

2. Chemically treat using normal dosage table if test results indicate any of the following:
   a. pH is less than 9.00.
   b. Phosphate is less than 10 ppm.

3. If pH and phosphate are in the free caustic region (with pH less than 10.90 for Type A boilers and less than 10.60 for Type B boilers) treat with DSP only per normal dosage table.

4. If pH is above 10.90 for a Type A boiler or 10.60 for a Type B boiler or if conductivity or chloride is out of limits, locate and correct the source of contamination. Ensure that the reserve feedwater meets requirements; dump, freshly fill, and treat the boiler.

NOTE

If any treatment action is taken during steps 2 or 3, defer further testing/treatment until after the boiler is on-line (see paragraph 220-31.45). If light-off is delayed and the boiler was treated on a prior to light-off sample, do not test or treat until the boiler is on-line and results indicate that treatment is required. Boilers shall be lighted off within 24 hours after being freshly filled.

220-31.58 BOILER WATER TREATMENT FOR TYPE A PROPULSION BOILERS

220-31.59 INITIAL TREATMENT.

Paragraphs 220-31.41 through 220-31.44 describe procedures for freshly filling and treating all propulsion boilers. Specific treatment instructions applicable to Type A boilers are included here. Trisodium phosphate is added to bring pH to the upper limit of 10.60 and to provide some of the needed phosphate. Disodium phosphate is added to bring phosphate to 100 ppm and not to the upper limit of 120 ppm. In order to determine the amount of chemicals needed, the volume of water requiring chemical treatment must be known. Table 220-31-4 lists this volume for each ship. Table 220-31-5 lists the weights of trisodium and disodium phosphates needed for initial treatment of the various volumes of water. The procedure is as follows:

WARNING

Wear a face shield when dissolving trisodium phosphate. Concentrated trisodium phosphate solutions are corrosive and cause burns to skin, eyes, and body tissues. Affected personnel shall flush skin with cold water. If trisodium phosphate or its solutions enter the eyes, flush with cold water for 15 minutes and obtain immediate medical attention.

1. Locate the boiler water volume for chemical treatment, in gallons, from Table 220-31-4.
2. Locate the weights of trisodium phosphate and disodium phosphate, in ounces, from Table 220-31-5.

NOTE

If the boiler is being freshly filled and treated following EDTA cleaning, treat with disodium phosphate only. Treat with both TSP and DSP if the boiler was water jetted after an EDTA cleaning.

3. Half fill the 10-liter safety dispensing bottle with feedwater at 50°C (122°F) or less.
4. Weigh the necessary amount of each phosphate treatment chemical, transferring each to the same 10-liter safety dispensing bottle. (See notes below.)
5. Add feedwater to the shoulder of the bottle, cap the bottle and spout, then shake to dissolve.
6. Inject the solution into the boiler in accordance with paragraph 220-31.44.

NOTE

The safety dispensing bottle shall be marked and used for boiler treatment chemicals only.

NOTE

As the trisodium and disodium phosphate dissolve they generate heat, so water temperature will increase slightly. Do not use very hot water to dissolve the chemicals because the safety dispensing bottle is made from linear polyethylene which has a maximum use temperature of 80°C (176°F). Trisodium phosphate can be added to water or vice versa without difficulty.

Table 220-31-4 BOILER WATER VOLUME FOR CHEMICAL TREATMENT OF TYPE A PROPULSION BOILERS

Boiler Water Volume(Gallons)	Ships
900	AD 15, 18, 19, AR 8
1,300	LSD 37-40
1,400	AS 36, LCC 19
1,500	AD 37, 38, 41-44, AE 24, 27, 28, 29, AFS 1-3, AS 33, 34, 39-41
1,600	AE 21, 22, AFS 4-7, LPH 2, 3, 7, 9-12, LCC 20
1,700	AE 23, 25, 32-35, AS 37, AOR 1-7
2,900	LKA 113-117, AO 177-180, 186

Table 220-31-5 CHEMICAL WEIGHTS NEEDED FOR FRESHLY FILLING TYPE A PROPULSION BOILERS

Boiler Water Volume for Chemical Treatment (Gallons)	Weights Required for Initial Treatment	
	TSP (Ounces)	DSP (Ounces)
900	18	11
1,300	26	16
1,400	28	17.5
1,500	30	18.5
1,600	32	20
1,700	34	21
2,900	58	36
16 ounces = 1 pound TSP = Trisodium Phosphate DSP = Disodium Phosphate		
Note Do not treat with TSP the first time a boiler is freshly filled after an EDTA cleaning. Treat with both TSP and DSP if the boiler was water jetted after an EDTA cleaning.		

NOTE

Large quantities of disodium phosphate should be added to water because disodium phosphate tends to cake if water is poured over it.

NOTE

The solubility of both trisodium and disodium phosphate is about 5 pounds per 10 liters of water at 50°C (122°F). If freshly filling large volume boilers (LKA 113 or AO 177 Class), two injections will be needed in order to dissolve the chemicals. Inject 1/2 of both chemicals each time.

220-31.60 STEAMING BOILERS.

Within 1/2 hour after placing a boiler on-line, then two additional samples 60 to 75 minutes apart, and at least every 8 hours thereafter (maximum 8 hours between samples), a boiler water sample shall be obtained and tested for pH, phosphate, conductivity, and chloride. Other sampling frequencies are listed in paragraph 220-31.45. Boiler water conditions in a steaming boiler shall be maintained in accordance with the following requirements:

pH	10.20 to 10.60
phosphate	50 to 120 ppm
conductivity	600 µmho/cm max
chloride	1.0 epm max

220-31.61 pH and Phosphate.

Since addition of trisodium phosphate to raise pH also raises phosphate, control of pH and phosphate are linked. The disodium phosphate provides additional phosphate as needed. The procedure is as follows:

WARNING

Wear a face shield when dissolving trisodium phosphate. Concentrated trisodium phosphate solution is corrosive and causes burns to skin, eyes, and body tissues. Affected personnel shall flush skin with cold water. If trisodium phosphate or its solutions enter the eyes, flush with cold water for 15 minutes and obtain immediate medical attention.

1. Determine the pH and phosphate concentrations in the boiler water from sample results.

2. Locate the boiler water volume for chemical treatment from Table 220-31-4.

3. Locate the boiler water pH from across the top of Table 220-31-6 then read down the column to find the weight of trisodium phosphate required for the appropriate volume. Record this weight in the log.

4. Continue to the last line of the column to find the phosphate correction. This is the amount that phosphate will increase because of the injection of trisodium phosphate. Record the phosphate correction in the log.

5. Add the phosphate correction caused by trisodium phosphate to the phosphate that was measured in the boiler water. This gives the corrected phosphate concentration. Record the corrected phosphate in the log.

6. Proceed to Table 220-31-7. Locate the corrected phosphate from across the top of the table, then read down the column to find the weight of disodium phosphate required for the appropriate volume. Record this weight in the log.

7. Weigh the chemicals, dissolve them together in the 10-liter safety dispensing bottle, and inject the solution into the boiler in accordance with paragraph 220-31.44. (Refer to the NOTES following paragraph 220-31.59 for information regarding treatment chemical solubility.)

Table 220-31-6 TRISODIUM PHOSPHATE DOSAGE FOR TYPE A PROPULSION BOILERS (TRISODIUM PHOSPHATE, DODECAHYDRATE, $NA_3 PO_4 \bullet 12H_2 O$)

Boiler Water Volume for Chemical Treatment (Gallons)	**Boiler Water pH**							
	<9.00	**9.00 to 9.09**	**9.10 to 9.19**	**9.20 to 9.29**	**9.30 to 9.39**	**9.40 to 9.49**	**9.50 to 9.59**	**9.60 to 9.69**
	Ounces of Trisodium Phosphate Required to Raise pH to 10.60							
900	18	18	18	17.5	17.5	17	16.5	16
1,300	26	26	25.5	25.5	25	24.5	24	23.5
1,400	28	28	27.5	27.5	27	26.5	26	25
1,500	30	30	29.5	29.5	29	28.5	28	27
1,600	32	32	31.5	31.5	31	30.5	29.5	29
1,700	34	34	33.5	33	33	31.5	31.5	30.5
2,900	58	58	57	56.5	56	55	54	52.5
	Phosphate Correction (ppm)							
	37.5	37.5	37.5	35	35	35	35	32.5
Boiler Water Volume for Chemical Treatment (Gallons)	**Boiler Water pH**							
	9.70 to 9.79	9.80 to 9.89	9.90 to 9.99	10.00 to 10.09	10.10 to 10.19	10.20 to 10.29	10.30 to 10.39	10.40 to 10.49
	Ounces of Trisodium Phosphate Required to Raise pH to 10.60							
900	15.5	15	14	12.5	11	9.5	7	4
1,300	22.5	21.5	20	18.5	16	13.5	10	5.5
1,400	24	23	21.5	19.5	17	14.5	10.5	6
1,500	26	25	23	21	18.5	15.5	11.5	6.5
1,600	28	26.5	25	22.5	20	16.5	12.5	7
1,700	29.5	28	26	24	21	17.5	13	7.5
2,900	50.5	48	45	41	36	30	22	12.5
	Phosphate Correction (ppm)							
	32.5	30	30	27.5	22.5	20	15	7.5
1 gallon = 3.785 liters 1 ounce = 28.35 grams 16 ounces = 1 pound								

Note

If pH is greater than 10.49, do not treat with TPS.

220-31.62

Table 220-31-8 shows some examples of chemical treatment calculations.

220-31.63

The disodium phosphate dosage table does not bring phosphate to the upper limit of 120 ppm but instead raises it to 100 ppm. The table is designed to allow a margin for phosphate in case it becomes necessary to treat only for pH since addition of trisodium phosphate to raise pH also increases phosphate. In addition, both dosage tables contain boiler water treatment volumes which are rounded to the nearest 100 gallons. The weights of chemicals are rounded to the nearest half ounce and are based on the amount needed for treating the higher number at the top of each column. For these reasons, chemical injection will not always bring boiler water to a pH of 10.60 exactly or to a phosphate of 100 ppm exactly. The pH could be low by 0.05 pH units and the phosphate by 5 ppm when analyzing the sample taken after chemical injection.

220-31.64

Addition of caustic soda to raise pH is only permitted under casualty control circumstances and with the permission of the Engineer Officer. Refer to paragraphs 220-31.108.5 and 220-31.108.7.

220-31.65

The boiler must never be surface blown, except in response to a high water casualty, if the action will cause boiler water to go below a pH of 10.20 and a phosphate of 50 ppm, or if conditions are in the free caustic region, **regardless of conductivity or chloride.** A 10-percent blowdown will cause phosphate, conductivity, and chloride to drop by 10 percent. The pH will drop by about 0.05 pH unit. The relationship between pH and blowdown is given in Table 220-31-9.

220-31.66

There are no **dump** limits for pH or phosphate. These parameters must be maintained under the control curve, Figure 220-31-4, and in limits. From the standpoint of feedwater consumption, a boiler whose pH is greater than 11 or whose phosphate is greater than 300 ppm should be dumped.

220-31.67 Conductivity.

Boiler water conductivity under various conditions can be approximated from the values given in Table 220-31-3. The conductivity level is controlled by surface blowdown. When boiler water reaches 1,800 µmhos/cm, more feedwater is used in surface blowdown than is used in securing the boiler and dumping the water. If boiler water conductivity exceeds 2,000 µmhos/cm for any reason, the boiler must be secured to stop carryover unless the Commanding Officer directs continued steaming. Refer to paragraph 220-31.99.

220-31.68 Chloride.

If feedwater quality is properly maintained, boiler water chloride will remain below 1.0 epm. Leakage of seawater into the feedwater system or abnormally high makeup rates will cause a continuous increase in the chloride level of boiler water.

220-31.69

If seawater contamination makes it difficult or impossible to maintain chloride at or below 1.00 epm find and isolate the source of the contamination and avoid contaminating other systems or boilers.

Table 220-31-7 DISODIUM PHOSPHATE DOSAGE FOR TYPE A PROPULSION BOILERS (DISODIUM PHOSOHATE, ANHYDROUS, NA_2 HPO 4

Boiler Water Volume for Chemical Treatment (Gallons)	**Corrected Boiler Water Phosphate, ppm**								
	0 to 10	**12.5 to 15**	**17.5 to 20**	**22.5 to 25**	**27.5 to 30**	**32.5 to 35**	**37.5 to 40**	**42.5 to 45**	**47.5 to 50**
	Ounces of Disodium Phosphate Required to Raise Phosphate to 100 ppm								
900	16	15	14.5	13.5	12.5	11.5	11	10	9
1,300	23.5	22	20.5	19.5	18	17	15.5	14	13
1,400	25	23.5	22	21	19.5	18	16.5	15	14
1,500	27	25.5	24	22.5	21	19.5	18	16.5	15

Table 220-31-7 DISODIUM PHOSPHATE DOSAGE FOR TYPE A PROPULSION BOILERS (DISODIUM PHOSOHATE, ANHYDROUS, NA_2 HPO 4 - Continued

Boiler Water Volume for Chemical Treatment (Gallons)	**Corrected Boiler Water Phosphate, ppm**								
	0 to 10	**12.5 to 15**	**17.5 to 20**	**22.5 to 25**	**27.5 to 30**	**32.5 to 35**	**37.5 to 40**	**42.5 to 45**	**47.5 to 50**
1,600	29	27	25.5	24	22.5	20.5	19	17.5	16
1,700	30.5	29	27	25.5	23.5	22	20.5	18.5	17
2,900	52.5	49	46	43.5	40.5	38	34.5	31.5	29
Boiler Water Volume for Chemical Treatment (Gallons)	**Corrected Boiler Water Phosphate, ppm**								
	52.5 to 55.0	57.5 to 60.0	62.5 to 65.0	67.5 to 70.0	72.5 to 75.0	77.5 to 80.0	82.5 to 85.0	87.5 to 90.0	92.5 to 95.0
	Ounces of Disodium Required to Raise Phosphate to 100 ppm								
900	8	7	6.5	5.5	4.5	3.5	2.5	2	1
1,300	11.5	10.5	9	8	6.5	5	4	3	1.5
1,400	12.5	11	9.5	8.5	7	5.5	4	3	1.5
1,500	13.5	12	10.5	9	7.5	6	4.5	3	1.5
1,600	14.5	13	11	9.5	8	6.5	5	3	1.5
1,700	15	13.5	12	10	8.5	7	5	3.5	1.5
2,900	26	23.5	20	17	14.5	11.5	9	5.5	3
16 ounces = 1 pound									
Note If corrected phosphate is greater than 95 ppm (pH/phosphate below coordinated phosphate curve,) do not treat DSP.									

Table 220-31-8 EXAMPLES OF BOILER WATER TREATMENT CALCULATIONS (TYPE A PROPULSION BOILERS)

Boiler Water Results		**Boiler Water Volume (Gallons)**	**Ounces TSPTo be Added**	**Phosphate Correction**	**Corrected Phosphate**	**Ounces DSPTo be Added**
pH	**Phosphate (ppm)**					
10.27	67.5	900	9.5	20	87.5	2
10.39	100	900	7	15	115	0
10.55	50	1,700	0	0	50	17
10.60	82.5	1,700	0	0	82.5	5
10.44	105	2,900	12.5	7.5	112.5	0
10.20	55	2,900	30	20	75	14.5
TSP = Trisodium Phosphate DSP = Disodium Phosphate						

Table 220-31-9 RELATIONSHIP BETWEEN PH AND BLOWDOWN

Percent Blowdown	**Decrease in pH Units**
5	0.02
6	0.03
7	0.03
8	0.04

Table 220-31-9 RELATIONSHIP BETWEEN PH AND BLOWDOWN -

Continued

Percent Blowdown	Decrease in pH Units
9	0.04
10	0.05
11	0.05
12	0.06
13	0.06
14	0.07
15	0.07
20	0.09
25	0.13
30	0.16
35	0.19
40	0.22
45	0.26
50	0.30
55	0.35
60	0.40

220-31.70 IDLE BOILER WATER.

It is mandatory to sample and test all idle boilers within 1 hour prior to light-off with the exception of a boiler that has been freshly filled and treated. Treat in accordance with paragraph 220-31.57.

220-31.71 BOILER WATER TREATMENT FOR TYPE B PROPULSION BOILERS

220-31.72 INITIAL TREATMENT.

Paragraphs 220-31.41 through 220-31.44 describe procedures for freshly filling and treating all propulsion boilers. Specific treatment instructions applicable to Type B boilers are included here. Trisodium phosphate is added to bring pH to the upper limit of 10.20 and to provide some of the needed phosphate. Disodium phosphate is added to bring phosphate to 50 ppm and not to the upper limit of 60 ppm. In order to determine the amount of chemicals needed, the volume of water requiring chemical treatment must be known. Table 220-31-10 lists this volume for each ship. Table 220-31-11 lists weights of trisodium and disodium phosphates needed for initial treatment of the various volumes of water. The procedure is as follows:

WARNING

Wear a face shield when dissolving trisodium phosphate. Concentrated trisodium phosphate solutions are corrosive and cause burns to skin, eyes, and body tissues. Affected personnel shall flush skin with cold water. If trisodium phosphate or its solutions enter the eyes, flush with cold water for 15 minutes and obtain immediate medical attention.

1. Locate the boiler water volume for chemical treatment, in gallons, from Table 220-31-10.
2. Locate the weights of trisodium phosphate and disodium phosphate, in ounces, from Table 220-31-11.
3. Half fill the 10-liter safety dispensing bottle with feedwater at 50°C (122°F) or less.
4. Weigh the necessary amount of each phosphate treatment chemical, transferring each into the same 10-liter safety dispensing bottle. (See NOTE)
5. Add feedwater to the shoulder of the bottle, cap the bottle and spout, then shake to dissolve.

NOTE

If the boiler is being freshly filled and treated following EDTA cleaning, treat with disodium phosphate only. Treat with both TSP and DSP if the boiler was water jetted after an EDTA cleaning.

6. Inject the solution into the boiler in accordance with paragraph 220-31.44.

NOTE

The safety dispensing bottle shall be marked and used for boiler water treatment chemicals only.

Table 220-31-10 BOILER WATER VOLUME FOR CHEMICAL TREATMENT OF TYPE B PROPULSION BOILERS

Boiler Water Volume (Gallons)	Ships
800	FF 1098
1,000	CG 16-18, 26-34, DDG 12, 15, 20, 22, 42, 43, 46, FF 1052-1097
1,200	AGF 3, DDG 14, 24, 39, LPD 1, 2, 4-6, LSD 32
1,300	AGF 11, CG 19-24, LPD 7-10, 12-15
1,600	LSD 36
1,800	CV 60, 61
1,900	AOE 1-3, CV 62
2,000	CV 67
2,100	CV 59
2,200	CV 63, 64, 66
2,300	AOE 4, BB 63
3,100	LHA 1-5, LHD 1

Table 220-31-11 CHEMICAL WEIGHTS NEEDED FOR FRESHLY FILLING TYPE B PROPULSION BOILERS

Boiler Water Volume for Chemical Treatment (Gallons)	Weights Required for Initial Treatment	
	TSP (Ounces)	DSP(Ounces)
800	6	5.5
1,000	7.5	7
1,200	9	8.5
1,300	10	9
1,600	12	11
1,800	13.5	12.5
1,900	14.5	13

Table 220-31-11 CHEMICAL WEIGHTS NEEDED FOR FRESHLY FILLING TYPE B PROPULSION BOILERS - Continued

Boiler Water Volume for Chemical Treatment (Gallons)	Weights Required for Initial Treatment	
	TSP (Ounces)	DSP(Ounces)
2,000	15	14
2,100	16	14.5
2,200	16.5	15.5
2,300	17.5	16
3,100	23.5	21.5
16 ounces = 1 pound TSP = Trisodium Phosphate DSP = Disodium Phosphate		

NOTE

As the trisodium and disodium phosphate dissolve they generate heat, so water temperature will increase slightly. Do not use very hot water to dissolve the chemicals because the safety dispensing bottle is made from linear polyethylene which has a maximum use temperature of 80°C (176°F). Trisodium phosphate can be added to water or vice versa without difficulty. Large quantities of disodium phosphate should be added to water because disodium phosphate tends to cake if water is poured over it.

NOTE

The solubility of both trisodium and disodium phosphate is about 5 pounds per 10 liters of water at 50°C (122°F).

220-31.73 STEAMING BOILERS.

A boiler water sample shall be obtained and tested for pH, phosphate, conductivity, and chloride within 1/2 hour after placing a boiler on-line, followed by two additional samples 60 to 75 minutes apart, and at least every 8 hours thereafter (maximum 8 hours between samples). Other sampling frequencies are listed in paragraph 220-31.45. Boiler water conditions in a steaming boiler shall be maintained in accordance with the following requirements:

pH	9.80 to 10.20
phosphate	25 to 60 ppm
conductivity	400 µmho/cm max
chloride	1.0 epm max

220-31.74 pH and Phosphate.

Since addition of trisodium phosphate to raise pH also raises phosphate, control of pH and phosphate are linked. The disodium phosphate provides additional phosphate as needed. The procedure is as follows:

WARNING

Wear a face shield when dissolving trisodium phosphate. Concentrated trisodium phosphate solution is corrosive and causes burns to skin, eyes, and body tissues. Affected personnel shall flush skin with cold water. If trisodium phosphate or its solutions enter the eyes, flush with cold water for 15 minutes and obtain immediate medical attention.

1. Determine the pH and phosphate concentrations in the boiler water from sample results.
2. Locate the boiler water volume for chemical treatment from Table 220-31-10.
3. Locate the boiler water pH from across the top of Table 220-31-12 then read down the column to find the weight of trisodium phosphate required for the appropriate volume. Record this weight in the log.
4. Continue to the last line of the column to find the phosphate correction. This is the amount that phosphate will increase because of the injection of trisodium phosphate. Record the phosphate correction in the log.
5. Add the phosphate correction caused by trisodium phosphate to the phosphate that was measured in the boiler water. This gives the corrected phosphate concentration. Record the corrected phosphate in the log.
6. Proceed to Table 220-31-13. Locate the corrected phosphate from across the top of the table, then read down the column to find the weight of disodium phosphate required for the appropriate volume. Record this weight in the log.
7. Weigh the chemicals, dissolve them together in the 10-liter safety dispensing bottle, and inject the solution into the boiler in accordance with paragraph 220-31.44. (Refer to the notes following paragraph 220-31.72 for information regarding treatment chemical solubility.)

Table 220-31-12 TRISOPIUM PHOSPHATE DOSAGE FOR TYPE B PROPULSION BOILERS (TRISODIUM PHOSPHATE, DODECAHYDRATE, $NA_3\ PO_4 \cdot 12H_2\ O$)

Boiler Water Volume for Chemical Treatment (Gallons)	**Boiler Water pH**						
	<9.00	9.00 to 9.09	9.10 to 9.19	9.20 to 9.29	9.30 to 9.39	9.40 to 9.49	
		Ounces of Trisodium Phosphate Required to Raise pH to 10.20					
800	6	6	6	5.5	5.5	5	
1,000	7.5	7.5	7.5	7	7	6.5	
1,200	9	9	8.5	8.5	8	8	
1,300	10	9.5	9.5	9	9	8.5	
1,600	12	12	11.5	11.5	11	10.5	
1,800	13.5	13.5	13	13	12.5	11.5	
1,900	14.5	14	14	13.5	13	12.5	
2,000	15	15	14.5	14	13.5	13	
2,100	16	15.5	15.5	15	14.5	13.5	
2,200	16.5	16.5	16	15.5	15	14.5	
2,300	17.5	17.0	17	16.5	15.5	15	
3,100	23.5	23.0	22.5	22	21	20	
	Phosphate Correction (ppm)						

Table 220-31-12 TRISOPIUM PHOSPHATE DOSAGE FOR TYPE B PROPULSION BOILERS (TRISODIUM PHOSPHATE, DODECAHYDRATE, $NA_3\ PO_4 \cdot 12H_2\ O$) - Continued

	15	15	12.5	12.5	12.5	12.5
Boiler Water Volume for Chemical Treatment (Gallons)	**Boiler Water pH**					
	9.50 to 9.59	9.60 to 9.69	9.70 to 9.79	9.80 to 9.89	9.90 to 9.99	10.00 to 10.09
	Ounces of Trisodium Phosphate Required to Raise pH to 10.20					
800	5	4.5	4	3.5	2.5	1.5
1,000	6	5.5	5	4	3	1.5
1,200	7.5	6.5	6	5	3.5	2
1,300	8	7	6.5	5.5	4	2
1,600	9.5	9	8.5	6.5	5	2.5
1,800	11	10	9.5	7	5.5	3
1,900	11.5	10.5	10	7.5	5.5	3
2,000	12	11	10.5	8	6	3.5
2,100	13	11.5	11	8.5	6.5	3.5
2,200	13.5	12	11.5	9	6.5	3.5
2,300	14	13	12	9.5	7	4
3,100	19	17.5	16	12.5	9.5	5
	Phosphate Correction (ppm)					
	12.5	10	10	7.5	5	2.5
	Note If pH greater than 10.49, do not treat with TSP.16 ounces = 1 pound					

220-31.75

Table 220-31-14 shows some examples of chemical treatment calculations.

220-31.76

The disodium phosphate dosage table does not bring phosphate to the upper limit of 60 ppm but instead raises it to 50 ppm. The table is designed to allow a margin for phosphate in case it becomes necessary to treat only for pH since addition of trisodium phosphate to raise pH also increases phosphate. In addition, both dosage tables contain boiler water treatment volumes which are rounded to the nearest 100 gallons. The weights of chemicals are rounded to the nearest 1/2 ounce and are based on the amount needed for treating the higher number at the top of each column. For these reasons, chemical injection will not always bring boiler water to a pH of 10.20 exactly or to a phosphate of 50 ppm exactly. The pH could be low by 0.05 pH units and the phosphate by 5 ppm when analyzing the sample taken after chemical injection.

220-31.77

Addition of caustic soda to raise pH is only permitted under casualty control circumstances and with the permission of the Engineer Officer. Refer to paragraphs 220-31.108.5 and 220-31.108.7.

220-31.78

The boiler must never be surface blown, except in response to a high water casualty, if the action will cause boiler water to go below a pH of 9.80 and a phosphate of 25 ppm, or if conditions are in the free caustic region, regardless of conductivity or chloride. A 10-percent blowdown will cause phosphate, conductivity, and chloride to drop by 10 percent. The pH will drop by about 0.05 pH unit. The relationship between pH and blowdown is given in Table 220-31-9.

220-31.79

There are no dump limits for pH or phosphate. These parameters must be maintained under the control curve (see Figure 220-31-4) and in limits. From the standpoint of feedwater consumption, a boiler whose pH is 10.6 or whose phosphate is 150 ppm should be dumped.

220-31.80 Conductivity.

Boiler water conductivity under various conditions can be approximated from the values given in the Table 220-31-3. The conductivity level is controlled by surface blowdown. When boiler water conductivity exceeds 1,200 µmho/cm, more feedwater is used in surface blowdown than is used in securing the boiler and dumping the water. If boiler water conductivity exceeds 2,000 µmho/cm for any reason, the boiler must be secured unless the Commanding Officer directs continued steaming. (Refer to paragraph 220-31.99.)

220-31.81 Chloride.

If feedwater quality is properly maintained, boiler water chloride will remain below 1.0 epm. Leakage of seawater into the feedwater system or abnormally high makeup rates will cause a continuous increase in the chloride level of boiler water.

220-31.82

If seawater contamination makes it difficult or impossible to maintain chloride at or below 1.00 epm, find and isolate the source of contamination, and avoid contaminating other systems or boilers.

Table 220-31-13 DISODIUM PHOSPHATE DOSAGE FOR TYPE B PROPULSION BOILERS (DISODIUM PHOSPHATE, ANHYDROUS, NA_2 HPO_4)

Boiler Water Volume for Chemical Treatment (Gallons)	**Corrected Boiler Water Phosphate, ppm**							
	0 to 10	**12.5 to 15**	**17.5 to 20**	**22.5 to 25**	**27.5 to 30**	**32.5 to 35**	**37.5 to 40**	**42.5 to 45**
	Ounces of Disodium Phosphate Required to Raise Phosphate to 50 ppm							
800	6.5	5.5	5	4	3	2.5	1.5	1
1,000	8	7	6	5	4	3	2	1
1,200	9.5	8.5	7	6	5	3.5	2.5	1
1,300	10.5	9	8	6.5	5	4	2.5	1.5
1,600	12.5	11	9.5	8	6.5	5	3	1.5
1,800	14	12.5	11	9	7	5.5	3.5	2
1,900	15	13.5	11.5	9.5	7.5	5.5	4	2
2,000	16	14	12	10	8	6	4	2
2,100	16.5	14.5	12.5	10.5	8.5	6.5	4	2

Table 220-31-13 DISODIUM PHOSPHATE DOSAGE FOR TYPE B PROPULSION BOILERS (DISODIUM PHOSPHATE, ANHYDROUS, NA_2 HPO_4) - Continued

Boiler Water Volume for Chemical Treatment (Gallons)	Corrected Boiler Water Phosphate, ppm							
	0 to 10	12.5 to 15	17.5 to 20	22.5 to 25	27.5 to 30	32.5 to 35	37.5 to 40	42.5 to 45
2,200	17.5	15.5	13	11	9	6.5	4.5	2
2,300	18.5	16	13.5	11.5	9	7	4.5	2.5
3,100	24.5	21.5	18.5	15.5	12.5	9.5	6	3
	Note If corrected phosphate is greater than 45 ppm (pH and phosphate below the coordinated phosphate curve), do not treat with DSP. (16 ounces = 1 pound)							

Table 220-31-14 EXAMPLES OF BOILER WATER TREATMENT CALCULATIONS (TYPE B PROPULSION BOILERS)

Boiler Water Results		Boiler Water Volume (Gallons)	Ounces TSP To be Added	Phosphate Correction	Corrected Phosphate	Ounces DSP To be Added
pH	Phosphate (ppm)					
9.86	32.5	1,000	4	7.5	40	2
10.15	35	1,000	0	0	35	3
9.82	50	1,300	5.5	7.5	57.5	0
10.12	50	1,300	0	0	50	0
9.43	40	1,800	11.5	12.5	52.5	0
9.43	22.5	1,800	11.5	12.5	35	5.5
9.99	45	3,100	9.5	5	50	0
9.99	50	3,100	9.5	5	55	0
TSP = Trisodium Phosphate DSP = Disodium Phosphate						

220-31.83 IDLE BOILER WATER.

It is mandatory to sample and test all idle boilers within 1 hour prior to light-off, with the exception of a boiler that has been freshly filled and treated. Treat in accordance with paragraph 220-31.57.

220-31.84 MAINTENANCE OF CHEMICAL TREATMENT LIMITS

220-31.85

The Navy boiler water treatment controls pH between 10.20 and 10.60, and phosphate between 50 and 120 ppm in Type A boilers. For Type B boilers, the pH limits are 9.80 to 10.20, and 25 to 60 ppm phosphate. These parameters will decrease because of treatment chemical losses during blowdown and from reaction of the chemicals with feedwater contaminants. It is not necessary to maintain pH and phosphate at or near the upper limits at all times. Each should be permitted to pass through the allowed range before re-treating. Continual treatment to the upper limit tends to mask signs of contamination that could otherwise be detected.

220-31.86

In certain situations, phosphate or pH varies from the required ranges even though a contaminating condition does not exist and the operator has made no error. Variations from the steaming boiler requirements of ±10 percent for phosphate and ±0.05 pH unit may occur under the following circumstances:

1. When idle boiler water is at a pH of 9.00 and a phosphate of 10 ppm, and the boiler is brought on-line, it is possible that a boiler water sample result will remain below the required range.
2. If the boiler water is below a pH of 9.00 and a phosphate of 10 ppm, and treatment is added prior to light-off, boiler water sample results may be high after the boiler is brought on-line.
3. If treatment chemicals are added to the water based on results obtained while steaming at low load, and the load is increased, results may be high.

220-31.87

Sampling frequency and testing requirements prevent long-term steaming with the boiler water out of limits. With the exception of light-off, all of these situations will be corrected within a short time frame, usually less than 90 minutes, when procedures are followed.

220-31.88 BOILER WATER SILICA.

Refer to Section 22 for control of boiler water silica.

220-31.89 CASUALTY CONTROL

220-31.90 GENERAL.

Casualties in plant chemistry control require prompt, well directed action to prevent or minimize plant damage. Plant casualty control procedures must be invoked to stop damage and to return conditions to normal. Troubles in monitoring chemistry conditions as a result of defective indicating devices, test equipment, sampling systems, or test chemicals may mask the symptoms of a casualty. These must be corrected in order to permit proper monitoring and control of plant chemistry.

220-31.91 RECOGNITION OF A CASUALTY.

Effective corrective action depends on timely recognition of a plant chemistry casualty. This in turn depends on all indicating systems and test equipment being in good working order and on watch standers being trained so that they recognize abnormal conditions. Casualties may be indicated by sample results, salinity/conductivity indicator readings, abnormal noises, temperatures, or pressures, high bilge water level, or some other unusual condition, which may occur anywhere in the plant. The Engineering Officer of the Watch (EOOW) must be thoroughly familiar with overall plant arrangement, principles of plant operation, symptoms of chemistry casualties, and casualty control procedures, so that he can properly evaluate reported abnormalities, identify the casualty and initiate appropriate corrective action. The Engineer Officer, MPA, and Oil King must be thoroughly familiar with all aspects of plant operation and chemistry control so that they can properly direct or advise the EOOW, can oversee corrective action, and can give timely, accurate information and advice to the Commanding Officer and Officer of the Deck.

220-31.92 CONFLICTING SYMPTOMS.

Initial symptoms of a casualty may be confusing or even appear to conflict with each other. The fundamental rule of good engineering practice - Believe your indications - means that action should be taken based on the worst symptom. If follow-up investigation shows the problem to be less severe, corrective actions can be easily adjusted. On the other hand, if an initial symptom of a serious problem is disregarded, severe plant damage may occur before effective action is taken to correct the problem.

220-31.93 SERIOUS CONTAMINATION OF BOILER WATER

220-31.94

Damage to the boiler or other parts of the plant will occur if boiler water is seriously contaminated. The damage may involve boiler scale formation, corrosion, or water carryover with the steam into the superheater. The types of damage and the conditions under which they will occur are:

1. Scale Formation may occur if the boiler is steaming with either:
   a. pH less than 9.00.
   b. Phosphate less than 10 ppm
2. Acid Corrosion will occur if the boiler water pH is less than 7.00. This will happen whether the boiler is steaming or idle.
3. Caustic Corrosion will occur if the boiler water pH and phosphate are in the free caustic region. This can only take place when the boiler is steaming.
4. Carryover will occur if the boiler is steaming under any of the following conditions:
   a. Conductivity of the boiler water is more than 2,000 μmho/cm.
   b. The boiler water sample contains oil.
   c. Foaming is visible in the boiler gauge glass.
5. Oxygen Corrosion will occur causing pitting and attack beneath deposits if water containing oxygen enters the boiler.

220-31.95 CRITERIA.

Boiler water contamination is serious if it causes any of the following conditions:

1. pH and phosphate in the free caustic region.
2. pH less than 9.00.
3. Phosphate less than 10 ppm.
4. Conductivity more than 1,500 μmho/cm.
5. Dissolved oxygen in the feedwater entering the boiler is greater than 15 ppb for more than 4 hours after detection.

220-31.96 SIGNIFICANT DAMAGE.

Significant and rapid damage is occurring when any of the following conditions exists:

1. pH is less than 6.00.
2. pH greater than 11.00.
3. Phosphate is zero.
4. Conductivity is greater than 2,000 µmho/cm.
5. Carryover of boiler water with the steam.
6. Dissolved oxygen in the feedwater entering the boiler is greater than 40 ppb for more than 2 hours after detection.

NOTE

The use of emergency cold suction should be avoided if at all possible, or minimized if it must be used by virtue of system design. Use of emergency cold suction causes entry of cold oxygenated water containing up to 8,000 ppb of dissolved oxygen directly into the boiler. Its use must be treated as any other high dissolved oxygen casualty.

220-31.97 ACTION.

Serious contamination of boiler water defined in paragraph 220-31.95 is a major casualty that demands immediate corrective action. Corrective actions must:

1. Control further damage.
2. Locate and isolate the source of contamination.
3. Remove contamination from the boiler water.
4. Make the plant ready to resume normal operation.

The following paragraphs describe the appropriate corrective actions. Figure 220-31-5 is a logic chart that can be used as a decision aid for treatment of boiler water in a seriously contaminated boiler with other than dissolved oxygen. The logic chart does not address the decision to secure the boiler. During serious contamination, boiler water samples are obtained 15 minutes after chemical addition or blowdown until boiler water has been returned to a moderate contamination zone or normal limits.

NOTE

If oil contamination has occurred, check salinity indicators for proper operation by chemical comparison test.

220-31.98 Control Damage.

Damage can be controlled by one or more of the following actions as required:

1. Securing the boiler (or minimizing the firing rate).
2. Injecting treatment chemicals to restore pH and phosphate.
3. Blowdown.
4. Restoring DFT to proper operation.

220-31.99

Secure the Boiler. Securing the boiler will stop all damage except acid and oxygen corrosion. Securing will reduce the effects of acid and oxygen corrosion. If the problem with the DFT cannot be corrected within 8 hours of detection, the boiler must be secured unless continued steaming is directed by the Commanding Officer. If the boiler must be steamed under serious contamination conditions (paragraph 220-31.95), the steaming rate should be minimized.

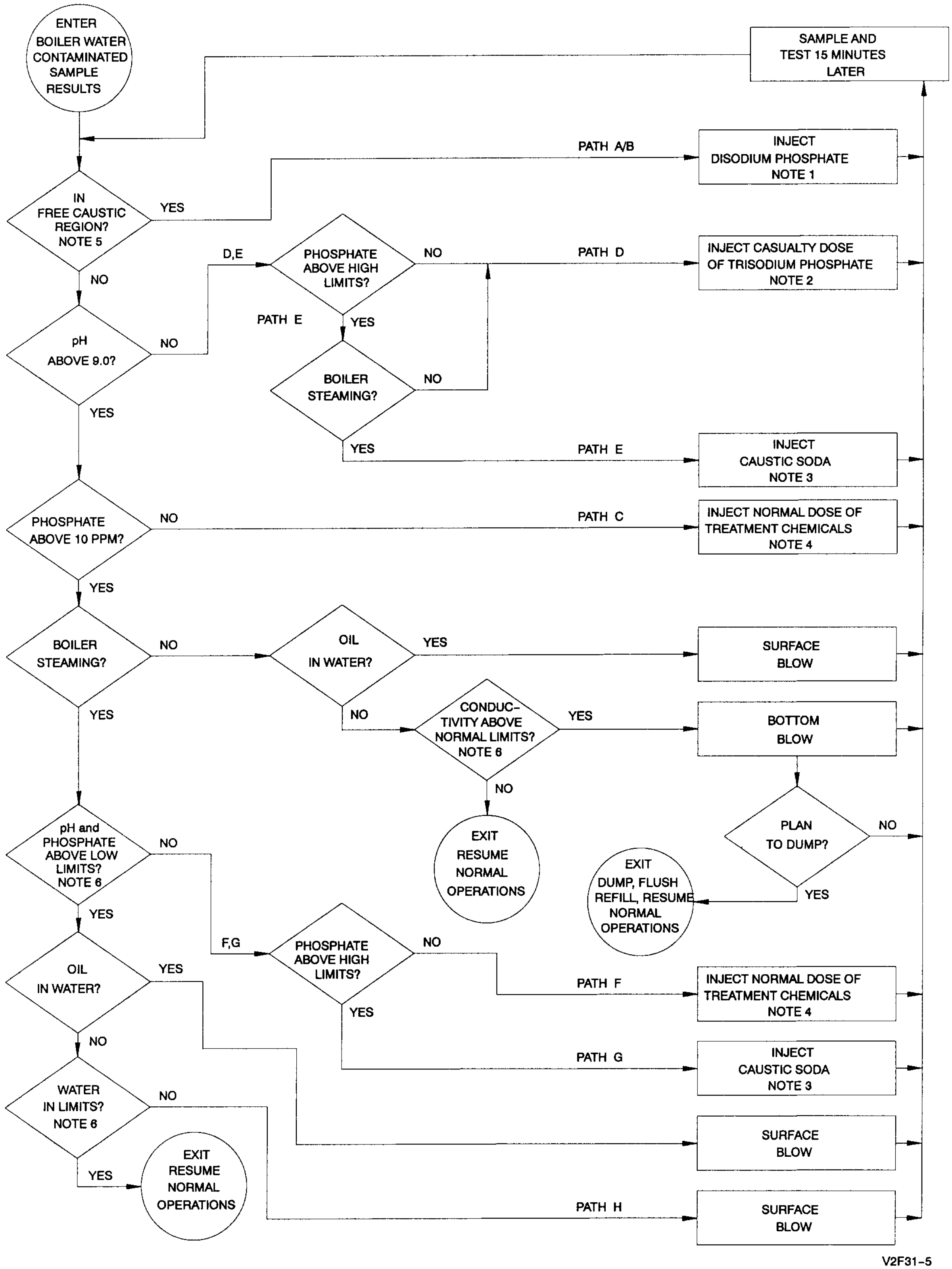


Figure 220-31-5 Logic Chart for Chemical Treatment of Seriously Contaminated Boiler Water (1 of 2)

Notes:

1. **The dose of disodium phosphate to inject is the amount required to get the boiler water into the coordinated phosphate region with phosphate above 10 ppm. It is calculated as described in paragraphs 220–31.108.1 and 220–31.108.2.**

2. **The casualty dose of trisodium phosphate is based on the boiler water chloride concentration. It is calculated as described in paragraph 220–31.108.4.**

3. **Caustic soda is to be injected only with the Engineer Officer's specific approval and only if the conditions for caustic soda injection described in paragraph 220–31.108.5 or 220–31.108.7 are met. Inject 1 ounce per 1,000 gallons of boiler water.**

4. **The normal dose of treatment chemicals is calculated from the dose tables for treating a steaming boiler given in Section 22.**

5. **Refer to Figure 220–31–6 through Figure 220–31–7, as appropriate, for the coordinated phosphate curve.**

6. **Refer to Table 220–31–2, boiler water limits. Also, abnormal color or odor indicates contamination and should be removed by blowdown.**

7. **The logic chart does not address the decision to secure a boiler. The decision to secure is a command decision. Paragraph 220–31.95 gives criteria for serious contamination. Paragraph 220–31.115 gives reporting requirements.**

Figure 220-31-5 Logic Chart for Chemical Treatment of Seriously Contaminated Boiler Water (2 of 2)

220-31.100 Guidance for Securing the Boiler.

When a boiler is seriously contaminated, prompt, well-directed action may result in regaining control of the casualty while the boiler is on-line at minimum load. In a few cases it is necessary to remain on-line to protect ship's safety, or to locate and correct the contamination source, or to avoid damaging another boiler.

220-31.101

If conditions reach a point of significant damage, the conditions must be controlled, the boiler must be treated and secured as soon as possible, and the contamination must be removed.

220-31.102

The following can be expected to occur under conditions of significant damage:

1. When pH is below 6, the boiler water contains hydrochloric acid (from seawater reactions) or sulfuric acid (from resin decomposition). Seawater contamination resulting in hydrochloric acid formation causes rapid and dangerous corrosion. Tube failures will occur within a few hours. Sulfuric acid from resin contamination is less dangerous in terms of catastrophic failure but tube failures can occur within a few days. Acid attack is suspected to be a contributor to crevice corrosion in drums and headers.
2. When pH is above 11.00 and deposits are present, it is very difficult to raise phosphate level sufficiently to prevent caustic corrosion without causing carryover. The option becomes a gouging of tubes (about 3 months to tube wall penetration) or carryover.

3. With no phosphate present, rapid scaling will occur. Acid or caustic attack will occur depending on the pH and this will be the greater immediate problem. Tube bulging and overheat from scaling will occur. The time to proceed to tube failure from scaling is not known but the process is probably slow (greater than a year).
4. A boiler which is experiencing severe, acute carryover will suffer superheater failure in 15 minutes to 1 hour. Chronic minor carryover will result in loss of the superheater in 3 to 6 months. Turbine blade damage will occur over a longer unknown time frame.
5. A boiler steaming with uncontrolled oxygen contamination in feedwater will require retubing in 6 to 9 months. Oxygen contamination is suspected to be a contributor to crevice attack in drums and headers.

220-31.103

Damage to the plant is cumulative. Once it has occurred, equipment cannot be returned to an undamaged condition.

220-31.104

When a condition of serious contamination other than dissolved oxygen is discovered, and one treatment action (chemical or blowdown) does not correct that condition, it is better to secure rather than to remain on-line for the sole purpose of treating or blowing down. Addition of treatment chemicals will be successful only while on-line, or immediately after securing. Only treat once after securing because further chemical addition will not be effective due to inadequate circulation. If after securing and treating the boiler, boiler water contamination remains serious, the boiler must be dumped.

220-31.105

The only conditions which will damage a secured boiler are low pH or high oxygen. It is preferable to accept these conditions in a secured boiler rather than in one which is on-line regardless of load.

220-31.106

If the cause of high oxygen in feedwater cannot be corrected within 8 hours of detection, the boiler must be secured and repairs effected to the DFT.

220-31.107

If a choice is available under conditions of significant damage, choose to secure.

220-31.108 Inject Chemicals.

Proceed with chemical injection as discussed below. Weigh chemicals to the nearest 1/2 ounce. Refer to the treatment zone charts, Figure 220-31-6 and Figure 220-31-7 for Type A boilers, or Figure 220-31-8 for Type B boilers.

1. If pH (above 10.9 for Type A; above 10.6 for Type B) and phosphate are in Zone A (above the coordinated phosphate curve), inject the casualty dose of disodium phosphate determined by the following procedures:
   a. Plot the actual boiler water phosphate and pH found from sample analysis on Figure 220-31-6 or Figure 220-31-8 as appropriate.
   b. Draw a horizontal line from the pH value to the coordinated phosphate curve.
   c. Draw a vertical line, from the intersection point of the pH horizontal line and the coordinated phosphate

curve, to the horizontal axis of the graph. Read the phosphate concentration at that point. This value is the minimum phosphate concentration required to bring boiler water into the coordinated phosphate region at the existing boiler water pH. Inject the amount of disodium phosphate (DSP) calculated by use of the equation given below.

The casualty dose of disodium phosphate is to be injected even though it may raise phosphate and con-

$$\text{DSP} = \frac{\text{minimum phos} - \text{actual phos}}{5} \times \frac{V}{1{,}000} \times 1.2$$

where: DSP = **the number of ounces of disodium phosphate to inject**

minimum phos = **the minimum required phosphate concentration, in ppm, determined in step c. above**

actual phos = **the actual boiler water phosphate concentration, in ppm, from sample results**

V = **boiler water volume in gallons**

ductivity above their normal high limits. If the boiler is secured prior to treatment, inject this dose as soon as possible after securing. If the boiler is steaming, sample 15 minutes later and re-treat as needed. Example (see Figure 220-31-9)

1,200 psi boiler, V =	1,000	gal
pH (from sample analysis) =	11.00	
minimum phos (from graph) =	100	ppm
actual phos (from sample analysis) =	10	ppm

$$\text{DSP} = \frac{100 - 10}{5} \times \frac{1{,}000}{1{,}000} \times 1.2 = 21.6 \text{ oz (rounded to 21.5 oz)}$$

2. If pH (10.9 or less for Type A, 10.6 or less for Type B) and phosphate are in Zone B (above the coordinated phosphate curve), inject the treatment chemicals in accordance with the normal dosage tables whether steaming or secured. If the boiler is steaming, sample 15 minutes later, and re-treat as needed.
3. If pH and phosphate are in Zone C (in the coordinated phosphate region with phosphate less than 10 ppm, and pH at least 9.00) inject treatment chemicals in accordance with the normal dosage tables in Section 22. Sample 15 minutes later, and re-treat as needed. If the boiler is not steaming do not inject chemicals, unless needed based on the results of the sample taken 1 hour prior to light-off.
4. If pH and phosphate are in Zone D (pH less than 9.00 with phosphate at or below the normal high limit), inject a casualty dose of trisodium phosphate (TSP). The casualty dose of trisodium phosphate is calculated by using the following equation:

   The casualty dose of trisodium phosphate is to be injected even though it may raise phosphate and con-

$$TSP = f + \left(\frac{epm\ Cl}{4} \times f\right)$$

where: TSP = the amount of trisodium phosphate to inject in ounces

f = the amount of trisodium phosphate required for treating the boiler when freshly filled, as discussed in Table 220–31–5 for Type A boilers and Table 220–31–11 for Type B boilers

epm Cl = the boiler water chloride concentration in epm, from sample results.

ductivity above their normal high limits. If the boiler is steaming, sample 15 minutes later and re-treat as needed. If the boiler is secured inject this dose as soon as possible after securing. **Example (assume Type B boiler)**

phosphate (from sample analysis) =	10	ppm
pH (from sample analysis) =	8.40	
chloride (from sample analysis) =	3.00	epm
boiler water volume =	1,000	gal
weight TSP from Table 220–31–11 =	7.5	oz

$$TSP = 7.5 + \left(\frac{3}{4} \times 7.5\right) = 13.1 \text{ oz (rounded to 13.0 oz)}$$

5. If pH and phosphate are in Zone E (pH less than 9.00 with phosphate above the normal high limit), and the boiler is steaming, inject caustic soda, 1 ounce per 1,000 gallons of boiler water, sample 15 minutes later, and re-treat as needed. If in Zone E but not steaming, inject the casualty dose of trisodium phosphate as soon as possible after securing in accordance with paragraph 220-31.108.4 above.

WARNING

Caustic soda solutions are corrosive and cause burns to skin, eyes, and body tissues. Affected personnel shall flush skin with cold water. If caustic soda or its solutions enter the eyes, flush with cold water for 15 minutes and obtain immediate medical attention.

CAUTION

Improper injection of caustic soda can drive pH up into the free caustic region, thereby causing caustic corrosion. Therefore, it is not to be injected unless ship's force is positive that the following conditions are met (if in doubt add TSP):

a. Boiler is steaming.

b. pH is less than normal low limit.

c. Phosphate is above the normal high limit.

d. Meter pH and chemical pH are consistent.

e. Engineer Officer’s permission has been given for the injection of caustic soda.

6. When pH and phosphate are in Zone F (in the coordinated phosphate region and below normal low limits but with pH at least 9.00 and phosphate at least 10 ppm) and the boiler is steaming, inject treatment chemicals in accordance with the normal dosage tables. Sample 15 minutes later and re-treat as needed. If the boiler is not steaming, no chemical injection is needed until after the boiler is on-line.

NOTE

pH and phosphate lying in Zone F do not necessarily indicate serious contamination. If pH and phosphate are in Zone F and none of the other indicators of serious contamination given in paragraph 220-31.95 exist, then moderate contamination has occurred. Refer to paragraph 220-31.117.

7. When pH phosphate are in Zone G (pH less than the normal low limit with phosphate above the normal high limit) and the boiler is steaming, inject caustic soda, in the amount of 1 ounce per 1,000 gallons of boiler water. Sample 15 minutes later and re-treat as needed. If the boiler is not steaming, do not treat unless needed based on results of the sample taken within 1 hour prior to light-off.

WARNING

Caustic soda solutions are corrosive and cause burns to skin, eyes, and body tissues. Affected personnel shall flush skin with cold water. If caustic soda or its solutions enter the eyes, flush with cold water for 15 minutes and obtain immediate medical attention.

CAUTION

Improper injection of caustic soda can drive pH up into the free caustic region, thereby causing caustic corrosion. Therefore, it is not to be injected unless ship’s force is positive that the following conditions are met (if in doubt add TSP):

a. Boiler is steaming.

b. pH is less than normal low limit.

c. Phosphate is above the normal high limit.

d. Meter pH and chemical pH are consistent.

e. Engineer Officer’s permission has been given for the injection of caustic soda.

NOTE

pH and phosphate values in Zone G do not necessarily indicate serious contamination. If pH and phosphate are in Zone G and none of the other indicators of serious contamination given in paragraph 220-31.95 exist, then moderate contamination has occurred. Refer to paragraph 220-31.117.

8. When pH and phosphate are in Zone H (pH or phosphate above normal high limits) and the boiler is steaming, inject treatment chemicals in accordance with the normal dosage tables if needed, to keep pH and phosphate from going below normal low limits on blowdown. Sample 15 minutes later and re-treat as needed. If the boiler is not steaming, do not inject chemicals unless needed based on results of the sample taken within 1 hour prior to light-off.

NOTE

pH and phosphate values in Zone H do not necessarily indicate serious contamination. If pH and phosphate are in Zone H and none of the other indicators of serious contamination given in paragraph 220-31.95 exist, then moderate contamination has occurred. Refer to paragraph 220-31.117.

9. When pH and phosphate are within normal limits and the boiler is steaming, inject treatment chemicals in accordance with the normal dosage tables if needed, to keep pH and phosphate from going below normal limits on blowdown. Sample 15 minutes later and re-treat as needed. If the boiler is not steaming, do not inject chemicals unless needed based on the results of the sample taken 1 hour prior to light-off.

NOTE

pH and phosphate values within normal limits do not necessarily indicate that contamination has not occurred. Indicators of serious contamination are listed in paragraph 220-31.95. Indicators of moderate contamination are listed in paragraph 220-31.117.

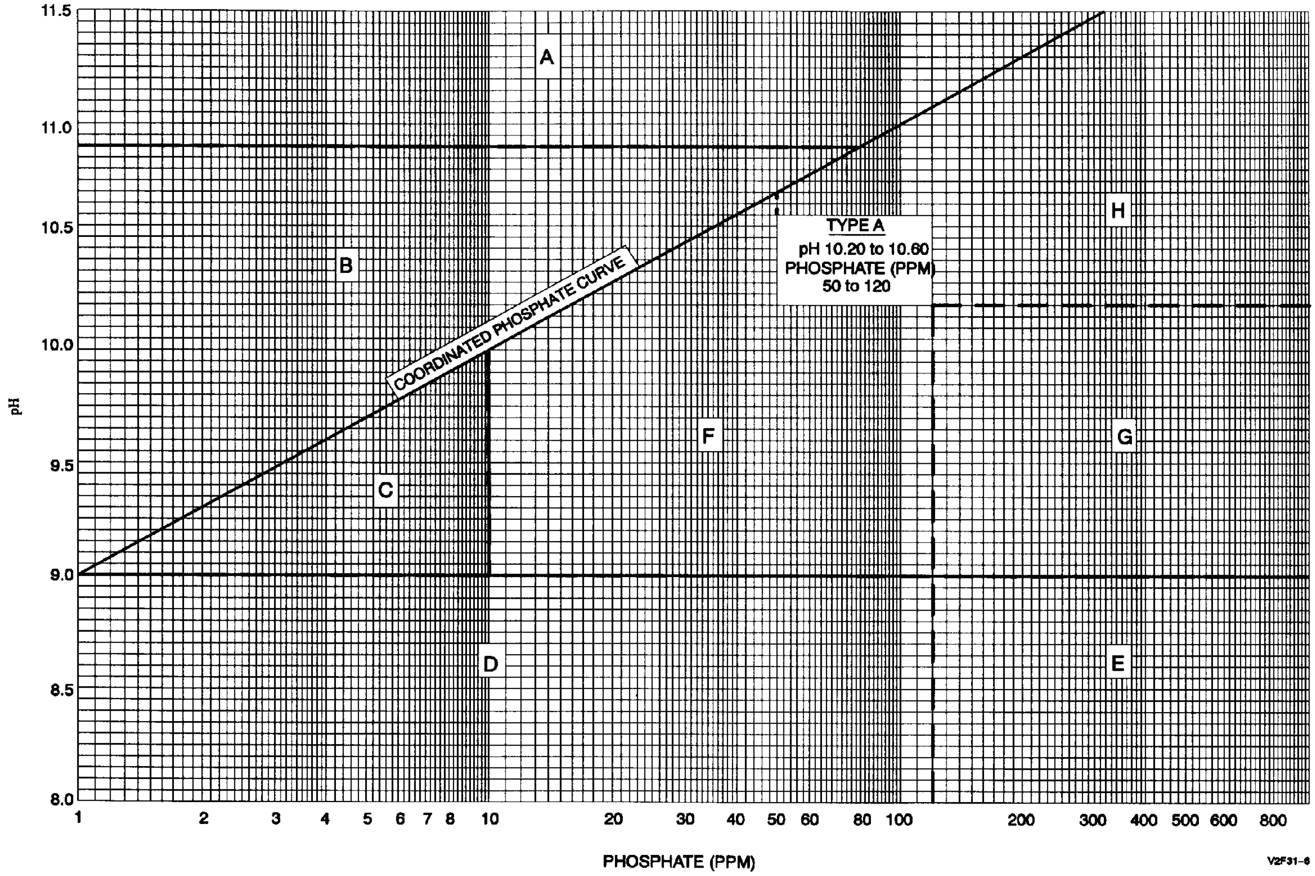


Figure 220-31-6 Coordinated Phosphate Treatment Zone Chart for Type A Boilers

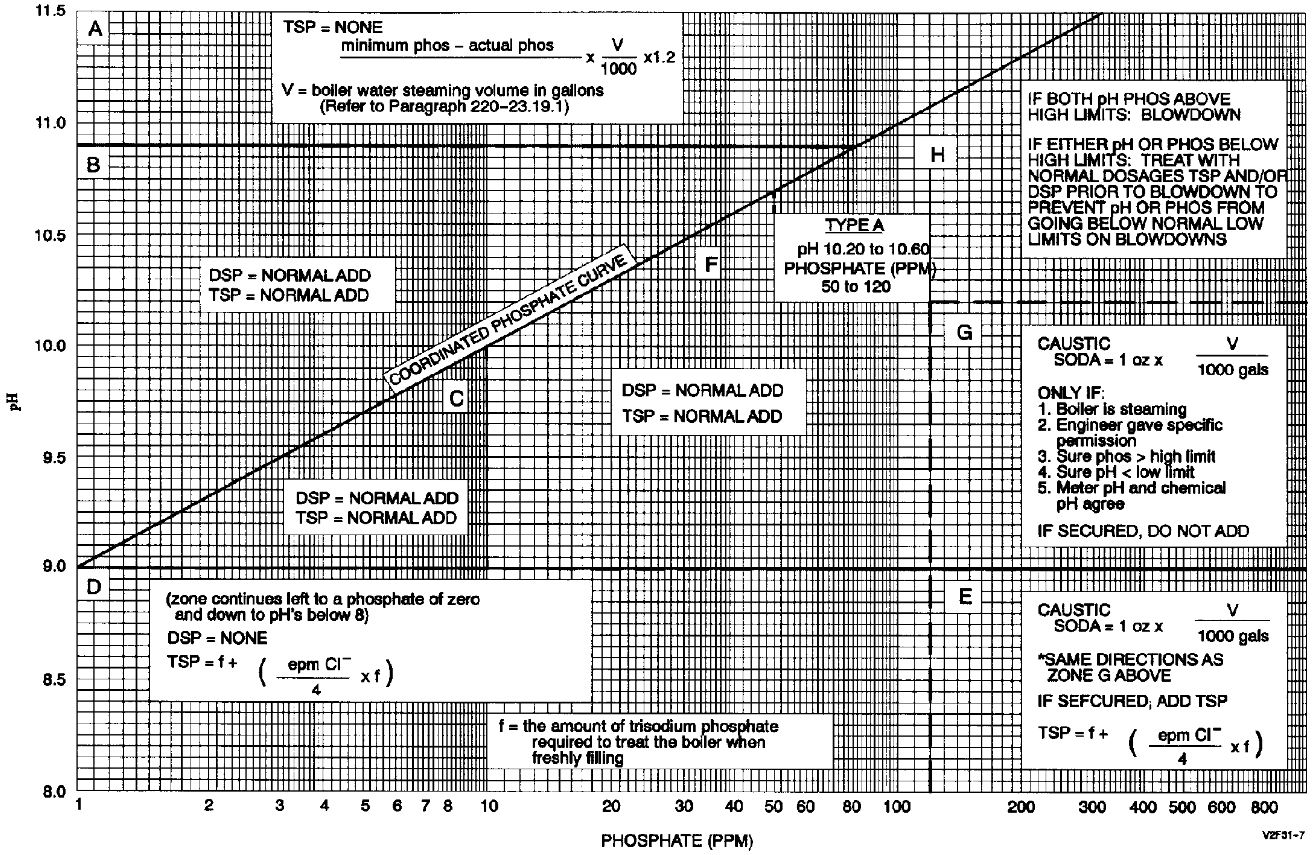


Figure 220-31-7 Coordinated Phosphate Treatment Zone Chart for Type A Boilers

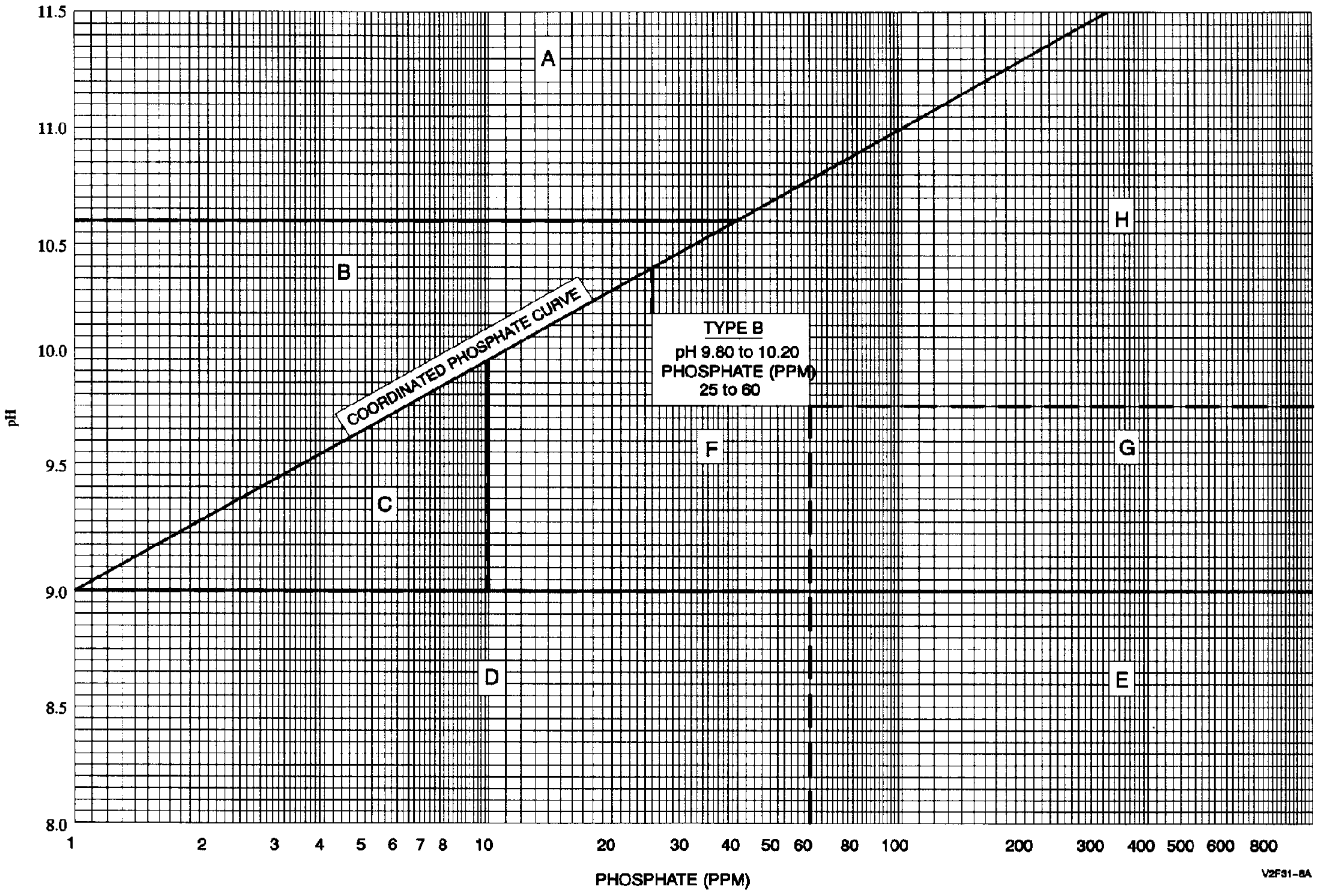


Figure 220-31-8 Coordinated Phosphate Treatment Zone Chart for Type B Boilers (1 of 2)

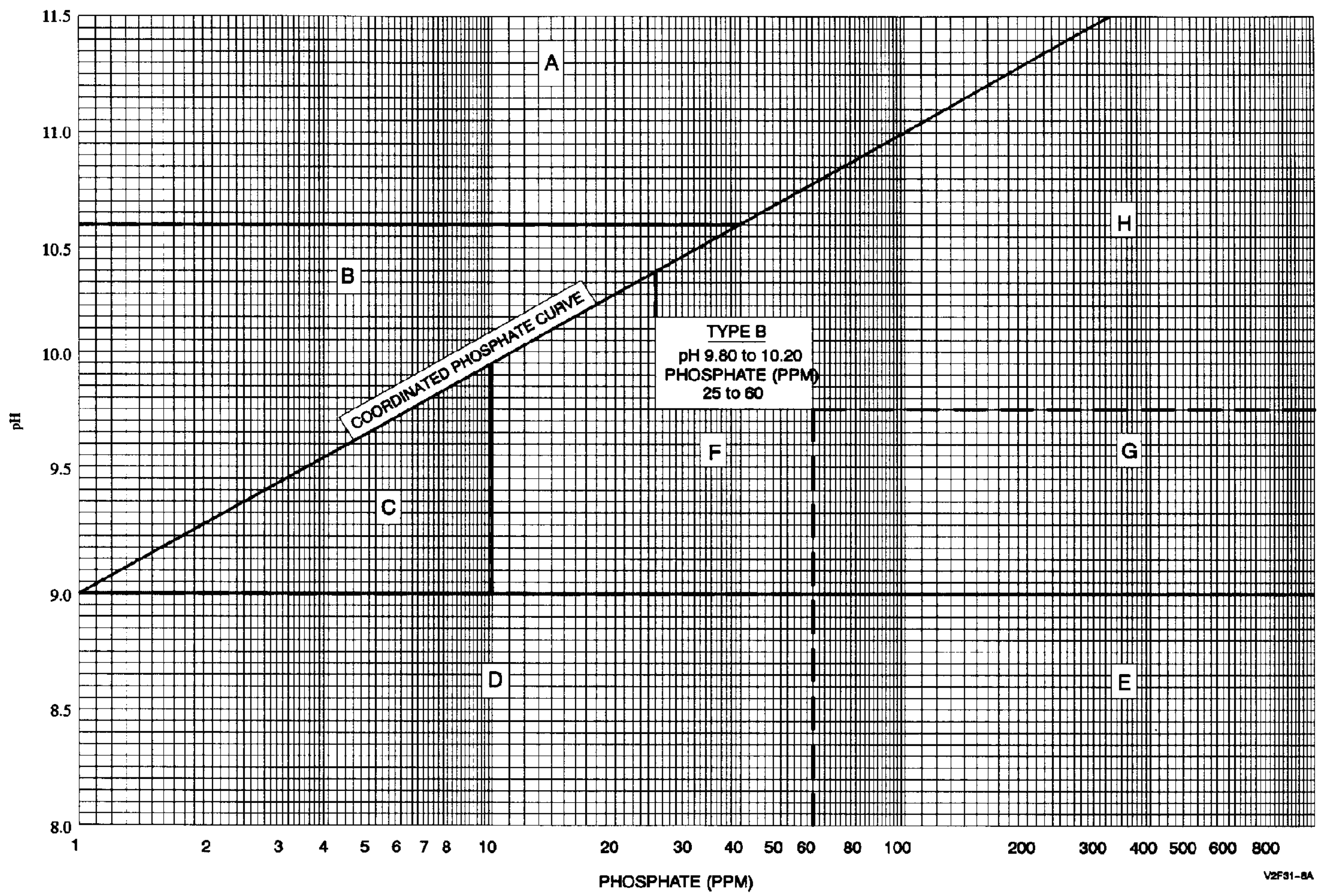


Figure 220-31-8 Coordinated Phosphate Treatment Zone Chart for Type B Boilers (2 of 2)

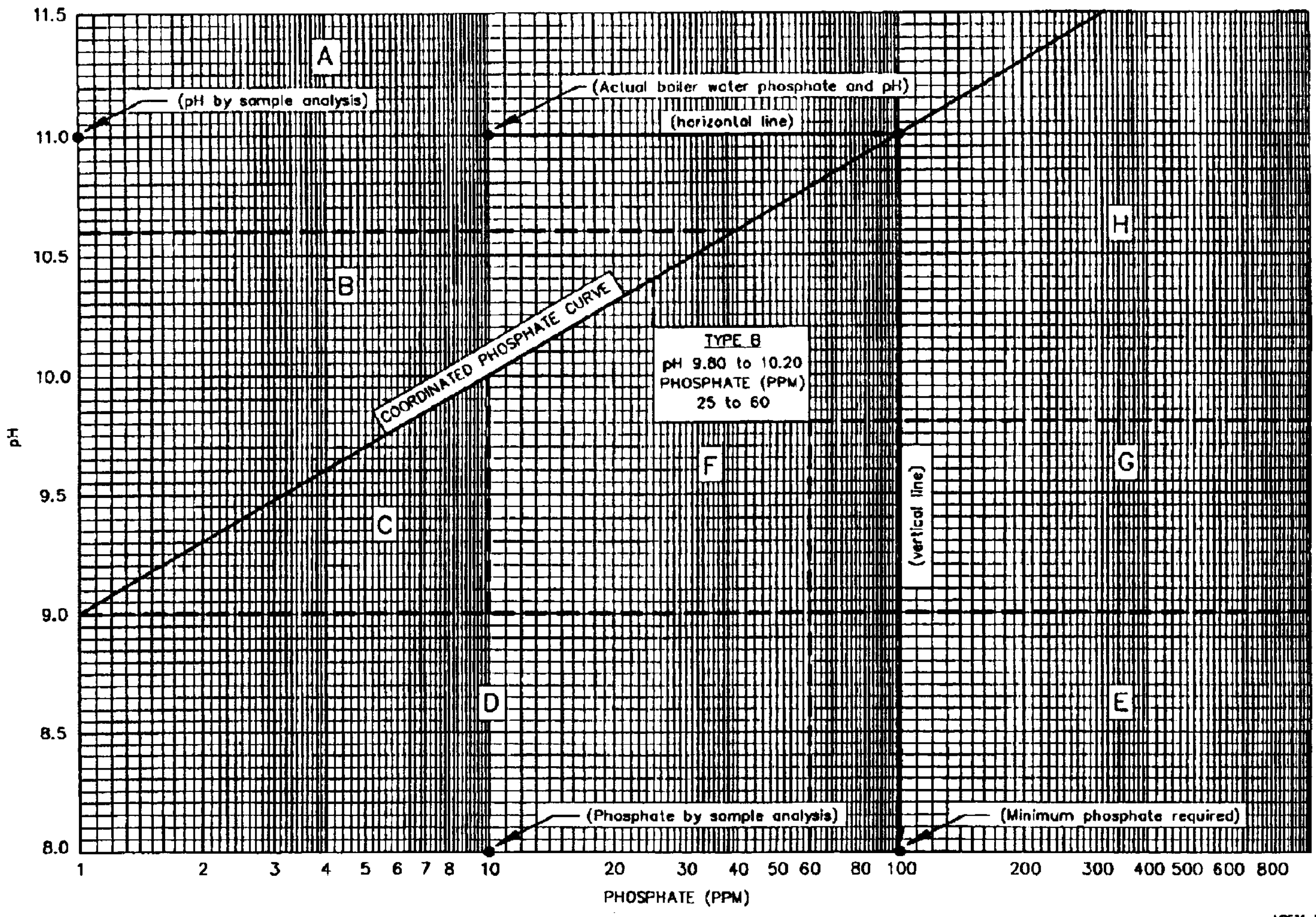


Figure 220-31-9 Example for Determining Minimum Phosphate Required if Water is in the Free Caustic Region

220-31.109 Locate and Isolate the Source of Contamination.

This should be done concurrent with securing and treating the boiler as discussed above. Locating the source of contamination depends on identifying the type of contamination. Refer to paragraph 220-31.110.

CAUTION

Another boiler should not be fed from the same feed system, or propulsion plants cross connected, until the source of contamination has been found and isolated, since doing so would contaminate another boiler.

220-31.110 Types of Contamination.

The types of contamination include seawater, shore water, oil, demineralizer resin, silica gel, silica (from poor quality shore source feedwater), corrosion products, debris, and improper boiler chemical injection. The following description of the effects of various types of contamination should enable operators to identify the type of contamination:

1. Seawater contamination will cause the following effects in boiler water:
   a. pH decrease.
   b. Phosphate decrease.
   c. Conductivity increase.
   d. Chloride increase.
2. Shore water contamination will cause the following effects in boiler water:
   a. pH increase.
   b. Phosphate decrease.
   c. Conductivity increase.
   d. Chloride may increase, but not so severely as with seawater contamination.
3. Oil contamination of a boiler water sample will cause the following effects:
   a. pH unchanged.
   b. Phosphate unchanged.
   c. Conductivity may or may not be affected.
   d. Chloride may or may not be affected.

NOTE

Oil present in boiler water may carryover into the steam and condensate system and contaminate salinity/conductivity indicators and make them ineffective.

4. Demineralizer Resin which has passed into the boiler water will cause the following effects in boiler water:
   a. pH will normally decrease and may be difficult to maintain.
   b. Phosphate may increase or decrease.
   c. Conductivity increase.
   d. Chloride increase.
   e. The water may have an odor of dead fish.
5. Desiccant (silica gel) which was left in a boiler after dry layup will cause the following effect in boiler water:
   a. pH will decrease as analyzed by the pH meter test. However, the emergency pH test by titration will indicate that pH is considerably higher than is shown by the meter test.
   b. Phosphate may be higher than expected.
   c. Conductivity will show that the pH meter value is correct.
   d. Chloride is not affected.

NOTE

If these effects are noted, test boiler water for silica (see paragraph 220-26.33). Refer to paragraph 220-22.89 for limits and corrective action. If silica contamination is suspected to be occurring, add trisodium phosphate if needed for boiler water pH adjustment until the contamination is corrected. Phosphate and emergency pH results are falsely high with silica present in boiler water. Do not add caustic soda; addition of caustic soda may cause entry into the free caustic region.

6. Silica from poor quality shore source feedwater will cause the following effects in boiler water:

a. pH as analyzed by the pH meter will not be affected. However, the emergency pH test by titration will indicate that pH is considerably higher than is shown by the meter test.

b. Phosphate may be higher than expected.

c. Conductivity will show that the pH meter value is correct.

d. Chloride is not affected.

NOTE

If these effects are noted, test boiler water for silica (see paragraph 220-26.33). Refer to paragraph 220-22.89 for limits and corrective action. If silica contamination is suspected to be occurring, add trisodium phosphate if needed for boiler water pH adjustment until the contamination is corrected. Phosphate and emergency pH results are falsely high with silica present in boiler water. Do not add caustic soda; addition of caustic soda may cause entry into the free caustic region.

7. Bicarbonate from shore source feedwater or shore steam condensate will cause the following effects in boiler water:

a. pH will increase.

b. Phosphate is not affected.

c. Conductivity will increase.

d. Chloride is not affected.

NOTE

If these effects are noted, check feedwater for phosphate using the boiler water phosphate test. If phosphate is indicated to be greater than 5.0 ppm, the water is contaminated with bicarbonate and must be dumped.

8. Excess Boiler Chemical Injection or injection of the wrong material may cause any of the following effects in boiler water:

a. Unexpected change in pH.

b. Unexpected change in phosphate.

c. Rise in conductivity.

d. Rise in chloride.

e. Unusual appearance of water.

9. Excess morpholine treatment of feedwater resulting in condensate/feedwater pH greater than 9.0 may cause any of the following effects in boiler water:

a. Boiler water and desuperheater phosphate results will be falsely high.

b. Calculated theoretical boiler water conductivity will be higher than that measured by conductivity meter.

c. Boiler water emergency pH results will be high when compared to those obtained from pH meter.

d. Boiler water conductivity measured by meter may show negligible increase.

e. Boiler water chloride levels will not be affected.

f. An ammonia-like odor may be present in samples.

NOTE

Secure the morpholine system and note its effect on boiler water. If silica contamination or overaddition of morpholine is suspected to be occurring, add trisodium phosphate if needed for boiler water pH adjustment until the contamination is corrected. Phosphate and emergency pH results are falsely high with silica or excess morpholine present in boiler water. Do not add caustic soda; addition of caustic soda may cause entry into the free caustic region.

10. Corrosion products will cause discoloration of the water and may cause changes in chemistry parameters.

11. Debris will cause abnormal appearance of the water and may cause changes in chemistry parameters.

220-31.111 Remove the Boiler Water Contamination.

This may be accomplished by blowdown or, if necessary, dumping, flushing, and refilling. Never blowdown a steaming boiler if pH and phosphate are in the free caustic region or if blowdown would reduce pH or phosphate below low limits, except in response to a high water casualty.

220-31.112

Surface blowdown will remove some of the dissolved contaminants and oil from a boiler. It is relatively ineffective in reducing high levels of dissolved contamination and sludge.

220-31.113

Bottom blowdown is effective in removing sludge from an idle boiler, and will also remove dissolved contaminants.

220-31.114 Sludge Removal and Inspection.

Serious boiler water contamination (as a result of seawater or shore water contamination), followed by proper chemical addition to restore pH and phosphate will generate a large amount of sludge. This must be removed by bottom blowdown as soon as the boiler can be secured. If the boiler is to be dumped because of a chemical casualty, bottom blowdown before dumping is still required. During the next upkeep or repair period following a serious contamination incident, boiler watersides should be opened for inspection to determine if cleaning is necessary. If boiler water conductivity exceeds 2000 µmho/cm, superheater steamsides shall be flushed and inspected in accordance with **NSTM Chapter 221** prior to further operation. If boiler water conductivity exceeds 8000 µmho/cm, boiler watersides and superheater steamsides shall be flushed and inspected in accordance with **NSTM Chapter 221** prior to further operation. Consideration should be given to removing, splitting, and crimping a screen tube to determine the need for acid cleaning if the boiler was steamed under conditions of significant damage (pH less than 6.00 or phosphate of 0 ppm). Light-off may result in pH or phosphate below limits. Low pH or phosphate in the after on-the-line (AOL) sample is not moderate or serious contamination unless other symptoms are present. In the absence of other indications of contamination, this temporary condition does not warrant waterside inspection.

220-31.115 REPORTS.

The cognizant activity (for example, ship, NAVSHIPYARD, SUPSHIP) shall provide a detailed message report within 24 hours to the Type Commander with an information copy to the ISIC, NSWCCD-SSES, and NAVSEA, if any of the following conditions occur:

1. The contamination reaches a condition of significant damage as defined in paragraph 220-31.96.
2. The boiler is steamed under conditions of serious contamination for more than eight hours.
3. Any time the Commanding Officer does not reduce the steaming rate under conditions of serious contamination after one treatment action fails to correct boiler water parameters to moderate contamination or within limits.

220-31.116

The information to be included in the report is contained in paragraph 220-31.231.

220-31.117 MODERATE CONTAMINATION OF BOILER WATER

220-31.118 DESCRIPTION.

Contamination of boiler water that affects the chemistry, appearance, or odor of the boiler water, but not so severely as to be classed as serious contamination under the criteria given in paragraph 220-31.95, is termed moderate contamination. Damage is not likely to occur under these conditions, but this moderate contamination is still a problem. If pH or phosphate is below normal limits, then there is very little protection against scale formation or corrosion from additional contamination. If conductivity is high, or if chloride is above 1.0 epm, there is less room for additional contamination to occur without causing carryover. Slight carryover may cause damage to stainless steel superheater tubes because of chloride present in the boiler water. Abnormal appearance or odor indicates a problem that could cause damage if left alone, and also indicates that something is wrong in the plant; in addition, abnormal color will interfere with seeing color changes during the chemical tests. Return pH and phosphate within normal limits by injecting treatment chemicals as appropriate. Sample 60 to 90 minutes later and re-treat as needed. Remove the contamination by blowdown. pH and phosphate must be kept within normal limits by chemical injection as necessary as long as the boiler is steaming. Concurrently, the source of contamination must be found and isolated.

220-31.119 UNUSUAL CONTAMINATION.

If unusual contamination occurs, or if contamination cannot be identified, it is good engineering practice to collect samples. NSWCCD-SSES can provide analytical support in defining contaminant sources. Ships may forward samples of boiler water, feedwater, or deposits from tubes or drums for analysis to Carderock Division Naval Surface Warfare Center, Code 622, Philadelphia, PA 19112-5083. The following guidelines apply when forwarding samples:

Samples should be in plastic bottles labeled with ship name, boiler or plant number, sample location, date and time of sample. The following information should be sent with the sample:

1. Shipboard analysis results for the sample.
2. Boiler water chemistry test results after contamination occurred or was discovered.
3. Boiler water and/or feedwater logs, if appropriate.
4. Summary of any corrective action taken.
5. Results of follow-up inspections, if any.

220-31.120

Forward water samples in a tightly capped plastic bottle sealed with tape (1 quart minimum). About 1/8 ounce of deposit removed from tubes or drums is needed to perform an analysis. Copies of correspondence shall be forwarded to NAVSEA and to the Type Commander.

220-31.121 pH OR PHOSPHATE OUT-OF-LIMITS: SUMMARY OF CHEMICAL TREATMENT ACTIONS

220-31.122

The fundamental principle underlying all water treatment actions is to maintain pH and phosphate within normal limits. This rule applies regardless of other water chemistry conditions in a steaming boiler. Steaming boiler water must be sampled frequently enough to establish trends and to allow timely action to keep pH and phosphate within normal limits. Any time feedwater contamination occurs, depletion of pH and phosphate should be expected, and the boiler must be sampled more frequently and treated accordingly. A steaming boiler must never be blown down if pH and phosphate are in the free caustic region or if the blowdown would reduce pH or phosphate below their low limits, except in response to a high water casualty.

220-31.123

The arrows in the lower right corner of Figure 220-31-4 show the approximate effects of various treatment actions. Note that caustic soda must never be injected into an idle boiler, and must never be injected into a steaming boiler if phosphate is below the upper limit. Extreme care must be taken to avoid overdosing with caustic soda, since this could drive pH up into the free caustic region, leading to caustic corrosion. It is for this reason that the Engineer Officer's specific approval is required for injection of caustic soda.

220-31.124 WATER CONTROL PROBLEMS: SYMPTOMS AND ACTION

220-31.125 CARRYOVER OF BOILER WATER WITH STEAM.

Carryover is a very serious problem because it causes damage to the superheater, turbines, and other steam plant components. Damage from carryover is both mechanical and chemical. Mechanical damage is a result of high velocity water droplets striking and eroding superheater tubes, headers, piping valves, and turbine blading. Chemical damage comes from the boiler water contaminants and treatment chemicals, carried over with the water, depositing on and possibly attacking metal surfaces. For example, boiler water chloride carried over into a stainless steel superheater can cause chloride stress corrosion of the stainless steel. Carryover can be caused by mechanical problems, such as improperly installed steam separators or other steam drum internals, or high boiler water level. Carryover can also be caused by contamination of the boiler water with oily material and seawater, shore water, or other material that causes the conductivity of the water to be high.

220-31.126 Symptoms.

Loss of boiler water pH, phosphate, conductivity, and chloride (with no blowdown being performed and no desuperheater leakage) indicates carryover or boiler water leakage. If one boiler is losing chemicals, requiring frequent treatment, while another fed from the same feed system is gaining chemicals or requires no treatment, either carryover or desuperheater leakage may be occurring. During operation, erratic fluctuations in superheater temperature are probably due to carryover, particularly if the boiler is at steady load. Foamy appearance of the water in the boiler gauge glass indicates carryover is probably occurring. If boiler water samples contain oil or scum, or have a conductivity in excess of limits, carryover should be suspected. If the conductivity of the sample exceeds 2,000 µmho/cm, it should be assumed that carryover is occurring. Large amounts of carryover will cause audible banging and rumbling in steam lines and turbines. Moderate carryover continuing for an extended period will cause a gradual rise in the salinity of steam drains and condensate. Steam drains and condensate should be analyzed for phosphate content; if phosphate of 5 ppm or more is found, that is a positive indicator of carryover if desuperheater leakage is not occurring. (Phosphate is determined by using the boiler water phosphate test. The presence of morpholine will cause false high phosphate test results. For ships with morpholine treatment, a desuperheater phosphate result of more than 10 ppm is an indication of a desuperheater leak or carryover.) The fact that carryover has occurred will be revealed, on inspection, by deposits of chemicals in the superheater, on steam valves, on turbine blading, and so on.

220-31.127 Action.

If carryover is occurring, the boiler must be secured to minimize damage, unless the Commanding Officer directs continued operation because of the operational situation. If operation must be continued, the firing rate should be minimized, and the boiler secured as soon as the operational situation allows. It must also be determined whether the cause is a mechanical problem or contamination of the water. If boiler water conductivity is within limits and the water is not oily, scummy, or otherwise abnormal, then the cause of carryover is mechanical and must be dealt with in accordance with **NSTM Chapter 221, Boilers** . If the conductivity is high, or oil, scum or other abnormal condition is present, or if foaming is visible in the boiler gauge glass, then the cause is contamination of the water. If the cause of carryover is contamination, then blowdowns should be performed to reduce the contamination, injecting chemicals as necessary between blowdowns to keep pH and phosphate within limits if the boiler is operating as discussed in paragraphs 220-31.93 through 220-31.114. Surface blowdown will usually be effective at removing oil contamination, especially if the steaming rate is low and the boiler water level is lowered to the surface blow line. If the boiler is secured, and carryover was due to high conductivity, dumping, flushing, and refilling will be the most effective method of eliminating the problem. The superheater of a boiler that has experienced carryover (for example, boiler water conductivity exceeds 2,000 µmho/cm) shall be flushed with hot feedwater and inspected prior to further operation in accordance with the procedures given in **NSTM Chapter 221** .

220-31.128 DESUPERHEATER LEAKAGE.

Desuperheater leakage allows boiler water, with contaminants and treatment chemicals, to enter the auxiliary steam systems. This causes deposits of boiler water contaminants and chemicals on valves, orifices, auxiliary turbines, and other desuperheater steam system components. These deposits can prevent components from operating properly, and can cause corrosion. In addition, the boiler treatment chemicals disappear from the boiler necessitating chemical addition. Salinity of drains and of condensate from auxiliary steam systems will be increased by the boiler water contaminants and treatment chemicals, making detection of seawater or other external contamination more difficult.

220-31.129 Symptoms.

Loss of boiler water pH, phosphate, conductivity, and chloride (with no blowdown being performed and no carryover taking place) indicates leakage of boiler water out of the boiler, possibly into the desuperheater. If one boiler is losing chemicals, requiring frequent treatment, while another fed from the same feed system is gaining chemicals or requires no treatment, either carryover or desuperheater leakage may be occurring. If an unusual rise in superheater outlet temperature occurs, or erratic fluctuations in desuperheater outlet temperature occur with the boiler at steady load and with superheater outlet temperature steady, probable desuperheater leakage is indicated. High salinity of auxiliary steam drains may indicate desuperheater leakage. Buildup of chemical deposits on desuperheated steam system valve and turbine packing glands is a positive indication of desuperheater leakage if boiler water carryover is not occurring. The presence of boiler chemicals (phosphate 5 ppm or greater) in condensate from the desuperheated steam is also a positive indication of desuperheater leakage if carryover is not occurring. (Phosphate in condensate is determined by using the boiler water phosphate test. The presence of morpholine will cause false high phosphate test results. For ships with morpholine treatment, a desuperheater phosphate test result of more than 10 ppm is an indication of desuperheater leak or carryover.)

220-31.130 Action.

Desuperheater leakage can be corrected only by opening the boiler and repairing the desuperheater as discussed in **NSTM Chapter 221** , and in the specific boiler technical manual or boiler repair manual. A boiler with a leaking desuperheater should not be operated unless necessary because damage to components supplied with desuperheated steam will eventually result. If the boiler must be steamed, then boiler water must be sampled and treated frequently to keep pH and phosphate within normal limits.

220-31.131 BOILER WATER LEAKAGE.

Boiler water can leak out of the boiler at rolled tube-to-tube sheet or tube-to-header joints, at handholes or manholes, through the blowdown system, the sampling system, the chemical injection system, the desuperheater, and through leaks in tubes and other pressure parts. The effect of this leakage on boiler water chemistry is the same as the effect of blowdown: conductivity, chloride, phosphate, and pH all decrease.

220-31.132 Symptoms.

Excessive feedwater consumption or a continuous decrease in boiler water conductivity, chloride, phosphate, and pH when no blowdowns or chemical injections are performed indicates either carryover or boiler water leakage. If carryover is not occurring, then leakage is. Carryover and desuperheater leakage can be identified as discussed in paragraphs 220-31.125 and 220-31.128. Other leakage can be found by examining each piping system connected to the boiler and by inspection of those handhole and manhole openings and boiler fittings that are accessible. Steam or water coming from any piping system or fitting suspected of boiler water leakage can be tested for phosphate using the boiler water phosphate test. If phosphate of 5 ppm or greater is found, then boiler water leakage is confirmed. (The presence of morpholine will cause false high phosphate test results. For ships with morpholine treatment, a phosphate result of more than 10 ppm is an indication of leakage.) Buildup of chemical deposits at valves and fittings indicates leakage.

220-31.133 Action.

A leaking boiler should not be operated unless necessary, because by themselves leaks always get worse, and the leak makes boiler chemistry control more difficult. If the boiler must be operated, boiler water must be sampled and treated more frequently to keep pH and phosphate within normal limits.

220-31.134 CHEMICAL HIDEOUT CAUSED BY CONCENTRATION OF CHEMICALS.

This form of chemical hideout refers to the decrease or disappearance of boiler water phosphate and pH not due to contamination, leakage or carryover. When hideout is occurring, the effect on phosphate is appreciable; the effect on pH is usually much smaller. Hideout makes control of boiler water chemistry more difficult, and it is usually a symptom of dirty watersides. In a boiler experiencing hideout caused by chemical concentration, phosphate and pH usually decrease when the boiler is operating at high power, necessitating frequent sampling and chemical injection to keep pH and phosphate above low limits. When the boiler is returned to low load after an extended period at high load, phosphate and pH may go up, requiring frequent blowdown to keep conductivity from exceeding its high limit. Chemical concentration usually occurs because of porous deposits on boiler watersides. At high firing rates, the boiler chemicals concentrate in the deposits therefore taking those chemicals out of solution in the bulk of the boiler water. Prevention of corrosion and scale formation depends on the pH and phosphate being in limits in the bulk of the boiler water; therefore, trisodium phosphate and disodium phosphate must be injected as necessary to keep pH and phosphate of samples within normal limits even though the chemicals that are hiding out are really still in the boiler. When firing rate is reduced, the concentration of boiler chemicals in the deposits decreases, so some of the chemicals that precipitated in the deposits at high firing rate redissolve and reappear in the bulk of the boiler water. This drives pH, phosphate, and conductivity of samples up, nece ssitating blowdown to keep them in limits. Hideout may also be due to anything that causes relative stagnation of water in small areas of the boiler. Crevices, pits, sharp bends in tubes, and the like, can cause local stagnation of the boiler water. Chemicals may concentrate in these stagnant areas, particularly if steam generation takes place in them.

220-31.135 Symptoms.

Decrease in boiler water phosphate and pH may be caused by hideout. If no blowdowns are being performed, contamination is not occurring, leakage is not occurring, and carryover is not occurring, then hideout is likely. Contamination will usually cause a rise in chloride and conductivity; hideout will not. Leakage and carryover will cause chloride and conductivity to drop along with pH and phosphate; hideout will usually not cause a drop in boiler water chloride. If hideout caused by chemicals concentrating is suspected, conduct the following test:

1. Within 90 minutes before securing the boiler, sample and test the boiler water. Do not treat the boiler water prior to securing.
2. Secure the boiler and allow it to remain secured for 2 hours without blowdown. Continue to feed the boiler as required to maintain normal boiler water level.
3. Retest the boiler water.

220-31.136

If the phosphate result is at least double the value obtained before securing the boiler, severe hideout is occurring. Any increase in phosphate after securing is an indication that hideout may be occurring.

220-31.137 Action.

A boiler experiencing severe concentration of chemicals should not be operated unless necessary because of the difficulty in keeping pH, phosphate, and conductivity within normal limits. If the boiler must be operated, then it must be sampled and treated or blown down frequently to keep pH and phosphate above low limits and in the coordinated phosphate region with conductivity below its limit. Hideout due to waterside deposits can be corrected only by cleaning watersides. Water-jet cleaning is usually effective. Mechanical tube punching is of less value. If hideout remains after water-jet cleaning, consider chemical cleaning and ensure that water-jet cleaning is accomplished after the chemical cleaning.

220-31.138 CHEMICAL HIDEOUT CAUSED BY REACTION OF CHEMICALS.

Chemical hideout caused by reaction of chemicals is characterized by a loss in phosphate and increase in pH of boiler water when boiler steaming rate is increased with the reverse occurring with decrease in steaming rate or upon securing. In a boiler experiencing hideout caused by chemical reaction, phosphate loss and pH increase at high steaming rates necessitate frequent sampling and chemical addition to maintain conditions under the coordinated phosphate curve. With a return to low steaming rates, or upon securing, phosphate rises and pH falls dramatically, requiring treatment to restore pH, and blowdown to reduce phosphate. Sodium phosphates appear to react with magnetite that is formed in steam generators. The reaction is facilitated by high temperature and heat transfer rates. As the reaction proceeds, phosphates are used up and pH rises. Anything that reacts with magnetite promotes the corrosion of steel since it is a thin and tenacious layer of magnetite that covers boiler surfaces under operating conditions. The accompanying increase in pH only exacerbates the potentially corrosive situation due to increased pH which can lead to free caustic conditions. Finally, the unstable compound which is forming at higher loads may have properties of a scale which could interfere with heat transfer. Maintaining pH and phosphate limits is necessary to prevent corrosion and scale formation from contamination. Because of complex and competing reactions, control of boiler water becomes extremely difficult. In most boilers, hideout of this type is most severe upon light-off after acid or EDTA cleaning.

220-31.139 Symptoms.

A pattern of decreasing boiler water phosphate and increasing pH with increasing steaming rates (with the reverse occurring at decreasing steaming rates or upon securing) may be caused by hideout. Hideout symptoms are similar to those of shore water contamination. Shore water contamination usually causes a slight rise in chloride; hideout will not. Hideout causes a pH drop and phosphate increase upon securing; shore water contamination does not.

220-31.140 Action.

Occasionally, the frequent sampling, treatment, and blowdown necessary to maintain pH and phosphate limits will gradually reduce the hideout problem. Hideout may continue to some degree. In the absence of contamination a continued inability to control boiler water limits with normal treatment may require an adjustment of pH and phosphate limits. If such a trend is apparent, advise of conditions in writing in accordance with paragraph 220-31.231. Upon receipt of written approval from the Type Commander, the directions for treatment specified in paragraphs 220-31.141 through 220-31.143 shall be followed.

220-31.141 SPECIAL BOILER WATER TREATMENT PROCEDURES FOR CHEMICAL HIDEOUT.

These treatment procedures, for the control of boiler water chemistry during chemical hideout caused by reaction of chemicals, are to be used only with the permission of the Type Commander. Since the chemical hideout is caused by the reaction of the phosphate ion with oxides on the boiler watersides, the less phosphate in the boiler water, the easier the effects of the hideout can be controlled. Therefore, the hideout treatment maintains lower pH and phosphate levels in the boiler water. The reduced levels are as effective against corrosion and scaling as are the normal treatment levels. However, there is less protection against contamination and therefore more frequent sampling is required. In order to reduce the phosphate as much as possible and still remain under the coordinated phosphate curve, it is necessary to vary the upper pH limit according to the phosphate.

220-31.142 TREATMENT LIMITS FOR CHEMICAL HIDEOUT.

Boiler water conditions in a steaming boiler shall be maintained in accordance with the following requirements:

pH	9.2 - 10.3 dependent on phosphate level
	(Refer to Zone Chart 220-31-10″)
phosphate	10 to 30 ppm
conductivity	300 µmho/cm maximum
chloride	1.0 epm maximum

220-31.143 MAINTENANCE OF BOILER WATER LIMITS.

The boiler water limits shall be maintained in accordance with all of the requirements for propulsion boiler water except as provided in this paragraph. Treat the boiler water as indicated in the Treatment Zone Chart for Chemical Hideout, Figure 220-31-10.

1. For initial treatment of a freshly filled boiler:
   a. Following EDTA cleaning (water-jet cleaning is preferred in boilers experiencing hideout), add DSP only in accordance with Table 220-31-5 or Table 220-31-11 as applicable. Treat with both TSP and DSP if the boiler was water jetted.
   b. All other cases, add TSP only in accordance with Table 220-31-5 or Table 220-31-11 as applicable.

2. Prior to light-off: Do not chemically treat if the pH is 8.0 or more, the phosphate is 10 ppm or more and the results are not in the free caustic region.

3. Obtain a routine sample as often as required to maintain the boiler water within limits but at least every 4 hours (maximum of 4 hours between samples).

4. Do not attempt to maintain the pH or phosphate at the upper limits. Chemical additions will not bring the pH or the phosphate to the upper limits.

5. Serious contamination criteria as defined in paragraph 220-31.95 is the same except pH is less than 8.0 and phosphate is 5 ppm or less. If one treatment action does not remove the boiler from a serious contamination region, secure the boiler. Continue treatment until the boiler is removed from serious contamination.

6. Prior to securing, treat only as required in zone chart, then secure.

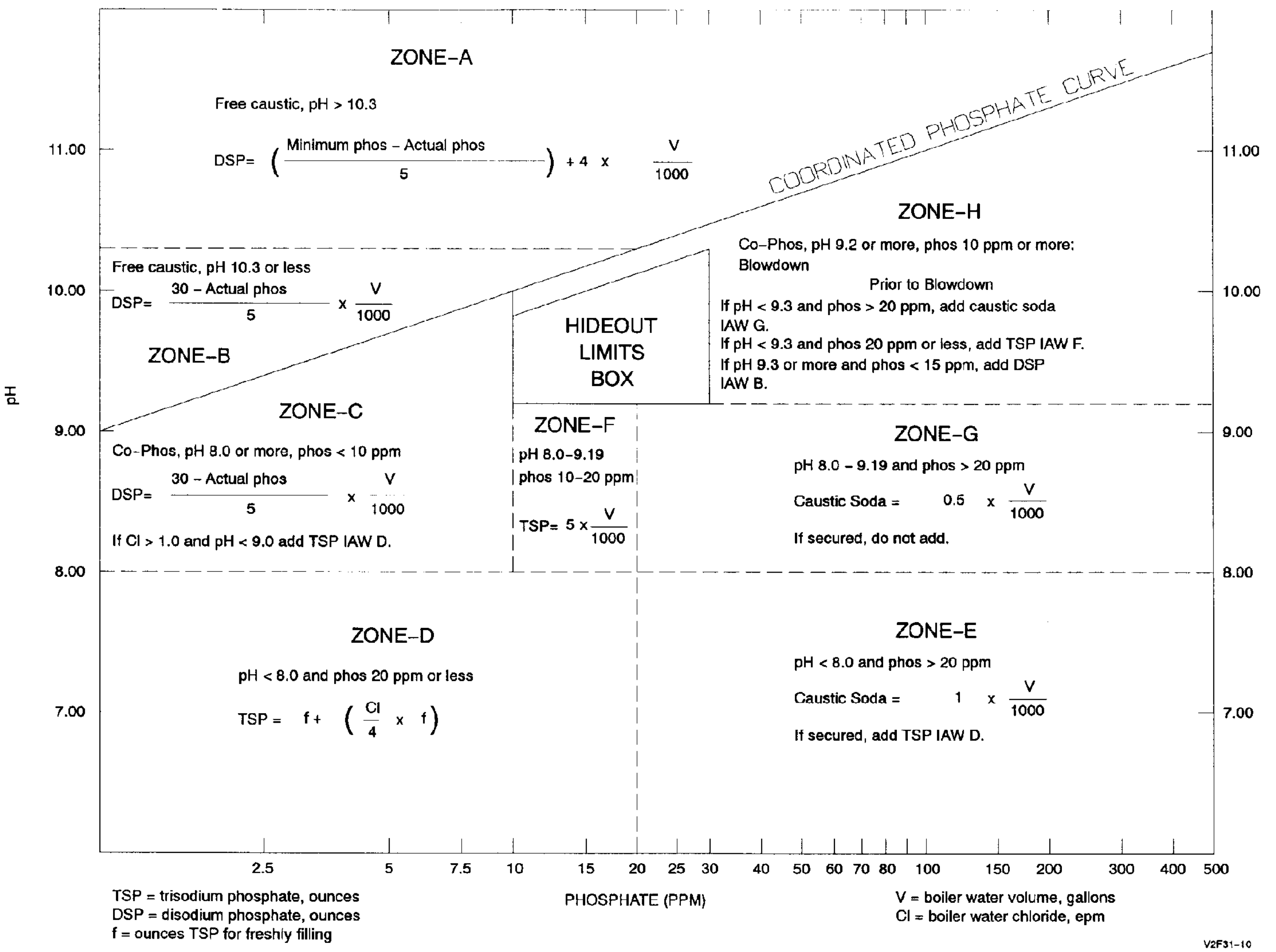


Figure 220-31-10 Coordinated Phosohate Treatment Zone Chart for Chemical Hideout Limits

220-31.144 BOILER CHEMISTRY PROBLEMS ON PLANT STARTUP.

Difficulties with plant chemistry control are often experienced during the initial period of operation following a prolonged shutdown period, especially if boilers were chemically cleaned, or extensive plant repair work was conducted. Frequent sampling and treatment of boiler water will be required to keep boiler water chemistry in limits and to remove suspended matter, discoloration and other abnormalities. Abnormal changes or conditions in boiler water should not be cause for alarm during this initial period unless pH, phosphate, and conductivity cannot be kept in limits or the abnormal conditions do not clear up within 5 operating days. If boiler water is too dirty to detect indicator color changes, secure the boiler, bottom blow, dump, flush systems that may contain the source of contamination, and begin again.

220-31.145 SEAWATER CONTAMINATION OF FEEDWATER.

Feedwater that is contaminated with seawater will cause seawater contamination of the boiler water. If it does occur, prompt action must be taken to prevent boiler damage. Refer to paragraphs 220-31.94 through 220-31.116. Concurrently, the source of seawater contamination must be found, isolated, and corrected so that normal plant operation can be resumed. Sources of seawater contamination include condenser leakage, bilge water drawn into condensate pumps and condensate piping in the bilge, contaminated makeup feed, contamination of evaporator drains, contaminated drains from service steam systems, and unauthorized steam or steam drain system connections to seawater systems or hull connections.

220-31.146 Symptoms.

Salinity/conductivity indicators are installed to monitor various points in the feedwater and condensate systems and in the distilling plants. Salinity/conductivity indicators in the feedwater and condensate systems provide a means for detecting and identifying the source of contamination in the boiler feedwater. However, in many Navy ships, alarms are not installed on feedwater and condensate system salinity/conductivity indicators; therefore, momentary shots of contamination and their sources are unlikely to be detected or identified before they enter the boiler. Ships that have alarms on all salinity/conductivity indicators in the feedwater and condensate systems are able to immediately detect and identify the source of such shots of contamination. Feedwater, condensate, or drains, which contain a low level of contamination, but below limits, can cause serious boiler water contamination in a matter of hours. This will be especially true if the plant is steaming at a moderate to high rate. All installed salinity/conductivity indicators must be frequently monitored by plant watch standers, and any reading above normal must be reported to the EOOW and the Oil King. When an abnormally high salinity/conductivity reading occurs, boilers being fed from the affected system should be immediately tested and appropriate chemistry casualty control action taken. It should always be suspected that contamination has occurred if bilge water gets high enough to cover any part of the condensate system or low-pressure steam drain system, or a reserve feed tank manhole. Bilges should be pumped to keep such high levels from occurring, and if such high bilge level does occur, salinity/conductivity indicators should be immediately checked and boiler water sampled and analyzed for contamination. Boiler water must be sampled frequently whenever feedwater contamination is known or suspected in order to maintain control of boiler chemistry. Refer to paragraphs 220-31.94 through 220-31.116.

220-31.147 Action.

The source of contamination must be found and isolated. At the same time, boilers being fed from the contaminated system must be sampled, and action taken to control boiler water chemistry in accordance with paragraphs 220-31.94 through 220-31.116.

220-31.148 Locating the Source of Contamination.

Salinity/conductivity cells may indicate the source of contamination directly. However, continuous contamination of less than 0.02 epm chloride, or contamination of an intermittent nature will be harder to find. Intermittent contamination is usually due either to bilgewater, service steam drains or makeup feed. Bilges should be pumped dry to eliminate that possible source. Makeup feed can be sampled and analyzed chemically for chloride contamination. Steam drains can be dumped to the bilge. Samples of steam drain condensate can be collected from various locations starting with the freshwater (or low-pressure) drain collecting tank, cooled to less than 37.8°C (100°F) and analyzed for chloride. After the bilges are pumped down, and drains and makeup feed are proven free of contamination or diverted to the bilge, then the water in a steaming boiler should be sampled to see if contamination is still occurring. If boiler water sample analysis indicates contamination is still occurring, it is most likely caused by a condenser leak. It may be difficult to detect a condenser leak by the chloride test because the chloride concentration may be low due to high condensate flow through the condenser. Prior to sampling main condenser condensate, it is preferable to reduce the steam/condensate flow through the condenser as much as possible (that is, slow the main engine). This has the effect of increasing chloride concentration by lowering condensate flow (due to lower steam flow) and increasing any seawater leakage which may be occurring by increasing condenser vacuum. Any leakage should concentrate enough to be detectable by the feedwater chloride test in a few minutes. Condensate flow rates from auxiliary condensers, drains and makeup feed are so low that significant contamination should be detectable without additional concentration.

220-31.149 SHORE WATER CONTAMINATION OF FEEDWATER.

Shore water differs from seawater in that total dissolved solids are lower, but the proportion of calcium hardness and silica in relation to chloride is much higher. Salinity/conductivity indicators are less effective at warning of shore water contamination than seawater contamination. It is likely that the first indication of shore water contamination will be in boiler water samples, which will show a drop in phosphate, an increase in pH and conductivity, with little change in chloride concentration. The source of shore water contamination must be found and isolated promptly.

220-31.150 Symptoms.

Shore water contamination of the boiler water indicates that the feedwater is contaminated with shore water. Hardness which is approximately equal to or greater than chloride in a feedwater sample indicates shore water contamination. It will most likely come from service steam drains or makeup feed.

220-31.151 Action.

If shore water contamination is occurring, find the source of the contamination by sampling the several possible points at which contamination could occur and analyzing for hardness, chloride and bicarbonate. Shore water contamination is usually caused by one of the following:

1. Leaking hot water heater coils when shore source potable water is in use and shipboard auxiliary steam is secured.
2. Leaking or missing check valves in direct contact type hot water heating piping while using shore source potable water.
3. Improper valve lineup or leaking/failed valves in feedwater/potable water system while taking on shore source potable water.

NOTE

Direct contact type steam heaters are not authorized for use in Navy ships and must be replaced whenever identified.

Shore source potable water can contaminate shipboard steam heating drain systems and result in deposits which cause contaminated steam drains for several days or more after shipboard steaming is resumed. When the source of the contamination is found, isolate and dump the contaminated water and repair equipment. Meanwhile, test the boiler water for contamination, and if present, take action as described in paragraphs 220-31.94through 220-31.116 or paragraph 220-31.118 as appropriate. If contamination persists after equipment repair, inspect hotel drain piping for evidence of deposits.

220-31.152 OIL CONTAMINATION OF FEEDWATER.

Oil contamination of feedwater may occur from several sources. These are as follows:

1. Leakage of lubricating oil from bearings into turbine glands, and then into the low-pressure drain system.
2. Leakage of oil into the steam in the lubricating oil purifier heater.

3. Leakage of oil into the steam heating coils in lubricating oil settling tanks.
4. Leakage of fuel oil into the steam side of fuel oil heaters if installed.
5. Leakage of fuel oil into a reserve feed tank through a hole in the bulkhead between adjacent tanks or through an improper piping lineup.
6. Spillage of oil into LP steam drain funnels.
7. Contamination of service steam drains from somewhere outside the propulsion plant.
8. Preservative or oil from steam plant components that were installed without proper cleaning.
9. Oily bilge water being drawn into condensate pumps or piping.
10. Oily bilge water leaking into double bottom reserve feed tanks.
11. Leakage of fuel oil into atomizing steam lines.

220-31.153 Symptoms.

Oil in the boiler water sample as discussed in paragraph 220-31.110 indicates possible feedwater contamination with oil.

220-31.154 Action.

Carry out the procedure for serious contamination of boiler water as discussed in paragraph 220-31.167. Find the source of oil contamination by examining water samples from all possible sources of oil and checking for visible oil or oily odor. Once the source is found, isolate and repair. Oil contamination in boiler water volatilizes and carries over with the steam into the steam and condensate system and coats condensate system salinity/conductivity probes, negating their effectiveness. If oil contamination is observed, check salinity/conductivity indicators for proper operation by chemical comparison test and clean probes, if necessary.

220-31.155 OXYGEN CONTAMINATION OF FEEDWATER.

Oxygen contamination of feedwater will cause dissolved oxygen attack of boiler tube metal.

220-31.156 Symptoms.

Dissolved oxygen concentration in feedwater, above 15 ppb indicates DFT malfunction. Refer to paragraphs 220-22.15 and 220-31.99.

220-31.157 Action.

Excess dissolved oxygen in the feedwater will cause boiler damage. The cause should be found and corrected as soon as possible. Plant operation should be minimized until the cause of the high dissolved oxygen is corrected. Possible causes are:

1. Improper operation of the DFT spray valves or steam atomizing valve.
2. Inadequate venting of the DFT.
3. Excessive water level in the DFT, flooding the steam atomizing valve.

4. DFT shell pressure higher than auxiliary exhaust pressure. This can be a temporary effect of large maneuvering transients, or a continuous effect of excess HP drain pressure in those ships where HP drains are piped directly to the shell of the DFT.
5. Inadequate recirculation and warmup of the DFT during plant startup.
6. Fluctuating auxiliary exhaust pressure as a result of a malfunction of the augmenting or unloading valve, malfunction of DFT level controls, or from erratic operation of steam driven auxiliaries.
7. A large shot of condensate that causes a sharp drop in DFT shell pressure, because of improper operation of a condensate pump, or sudden opening of the condensate cross connect valve or DFT condensate inlet valve.

220-31.158 OTHER FEEDWATER CONTAMINATION.

Some contaminant in the feedwater other than those discussed above will probably cause abnormal chemical behavior, appearance, or odor in the boiler water and in the feedwater. The source of this contamination must be found, isolated, and corrected, while taking action to control boiler chemistry. Refer to paragraphs 220-31.94 through 220-31.116 and 220-31.118.

220-31.159

Some examples of other contamination include:

1. Dirt or debris.
2. Corrosion products.
3. Demineralizer resin.
4. Desiccant.
5. Silica and bicarbonate from poor quality shore source feedwater.

220-31.160 MORPHOLINE OVERTREATMENT.

In ships with morpholine condensate treatment, feedwater pH is controlled by adjusting the morpholine flow rate. Overtreatment with morpholine can occur when the flow meter setting is too high, when the incorrect float is used, or when the morpholine treatment system is not secured when the plant is secured. Excess morpholine will also be present following light-off of a boiler under hydrazine/morpholine layup. Morpholine overtreatment is indicated by feedwater pH above 9. The salinity/conductivity indicators will also read higher than usual, and the comparison test results will show the indicator reading to be greater than the chemical test result by more than 0.04 epm.

220-31.161 EFFECT OF MORPHOLINE OVERTREATMENT ON BOILER WATER.

Gross overtreatment of condensate with morpholine will effect boiler water test results as follows:

1. The emergency pH (chemical pH) will be higher than the pH measured by the pH meter.
2. Boiler water phosphate test results will be falsely high.
3. Calculated (theoretical) conductivity will be higher than the measured conductivity.

When feedwater pH is over 9.0 and the above conditions are observed, morpholine overtreatment is occurring. Take the following corrective action:

1. Secure the morpholine condensate treatment system.
2. Sample the boiler every 4 hours until test results return to normal.
3. Maintain boiler water pH with trisodium phosphate only (no caustic soda) until boiler water test results indicate morpholine overtreatment has been corrected.
4. Do not blowdown the boiler unless measured boiler water conductivity exceeds limits.
5. After boiler water test results return to normal, resume morpholine treatment to maintain feedwater pH between 8.6 and 9.0.

NOTE

The symptoms of silica contamination are similar to those of morpholine overtreatment. If silica contamination is suspected, test the boiler water for silica in accordance with paragraph 220-26.33.

220-31.162 SODIUM NITRITE CONTAMINATION.

Sodium nitrite is used for wet layup of idle boilers. Sodium nitrite contamination occurs due to insufficient flushing of the boiler and associated DFT and feedwater piping following sodium nitrite layup, hydrostatic testing with sodium nitrite treated water or leakage of the layup or hydrostatic test solutions into the steam or drain systems. It is essential that the boiler and all feedwater components exposed to sodium nitrite are flushed prior to feeding the boiler for light-off. Sodium nitrite contamination will effect boiler water/feedwater test results in a steaming boiler as follows:

1. Feedwater chloride will be falsely high and end point may be difficult to detect.
2. Feedwater salinity/conductivity will increase.
3. Boiler water pH will increase.
4. Boiler water conductivity will increase.
5. Chloride test results for a steaming boiler are not usually affected. However, upon boiler light-off, chloride results for after on-line sample may be falsely high until the nitrite has dissipated.

Sodium nitrite contamination is corrected by using the appropriate casualty control procedures based test results.

220-31.163 CASUALTY CONTROL PROCEDURES

220-31.164 INDIVIDUAL SHIP PROCEDURES.

Individual ship casualty control procedures shall conform to the procedures given below. For explanation, refer to the principles of plant chemistry casualty control given earlier in this section.

220-31.165 PROCEDURE OUTLINES.

The next several paragraphs outline casualty procedures for several plant chemistry casualties. These are as follows:

1. Serious contamination of boiler water.

2. Moderate contamination of boiler water.
3. Boiler water carryover.
4. Leakage of boiler water.
5. Seawater contamination of feedwater.
6. Shore water contamination of feedwater.
7. Oil contamination of feedwater.
8. High dissolved oxygen in feedwater.
9. Overtreatment of feedwater with morpholine.
10. Sodium nitrite contamination of boiler water.
11. Other contamination of feedwater.

220-31.166

For each casualty, a reference is given to the paragraph of this section that provides a complete description of the casualty, abbreviated lists of symptoms and possible causes are given, and step-by-step plant corrective actions are outlined. The actions are broken down into Immediate Actions required to place the plant in a safe condition, and Follow-up Actions for making the plant ready for normal operation. The Immediate Actions must be taken promptly. The EOOW and other watch standers must refer to the procedure to verify that Immediate Actions are complete, and then proceed with the Follow-up Actions to make the plant ready to resume normal operations.

220-31.167 Procedure Outline: SERIOUS CONTAMINATION OF BOILER WATER.

Reference paragraphs 220-31.94 through 220-31.116.

1. Symptoms Any of the following conditions indicates serious contamination of the boiler water:
   a. Boiler water pH and phosphate in the free caustic region.
   b. pH less than 9.00.
   c. Phosphate less than 10 ppm.
   d. Conductivity more than 1,500 µmho/cm.
   e. Feedwater dissolved oxygen is greater than 15 ppb for more than 4 hours after detection. (Refer to paragraph 220-31.175.)
2. Possible causes
   a. Seawater contamination of the feedwater.
   b. Shore water contamination of the feedwater.
   c. Oil contamination of the feedwater.
   d. Demineralizer resin in the feedwater.
   e. Dirt, debris, corrosion products or other contamination of the feedwater.
   f. Injection of wrong, contaminated or excessive chemicals into the boiler.
   g. Improper alignment of DFT.
3. Immediate Actions
   a. Test and treat in accordance with 220-31.108.

b. If one treatment action does not return the boiler to a condition of moderate contamination or within limits, secure the boiler unless the Commanding Officer directs continued operation. If operation must be continued, minimize the firing rate until boiler water chemistry is within limits and the source of the contamination is isolated or corrected.

c. Initiate action to identify the type and source of contamination. Take corrective action in accordance with the appropriate procedure for feedwater contamination.

NOTE

The casualty dose of chemicals to be injected depends on the values of pH, phosphate and chloride concentration in the most recent sample, and is to be calculated as described in paragraph 220-31.108.

4. Follow-up Actions

a. Continue to sample the boiler water frequently until conditions are returned to normal.

b. Inject chemicals as necessary to keep pH and phosphate within normal limits as long as the boiler is steaming.

c. Carry out the procedure for carryover of boiler water, paragraph 220-31.127, if boiler water conductivity exceeds 2,000 µmho/cm, if oil or foaming are visible in the water, or if carryover is known to be occurring.

d. Carry out the procedure for damage to a boiler pressure part as discussed in **NSTM Chapter 079 Volume 3, Damage Control - Engineering Casualty Control** , if a boiler tube or other pressure part ruptures.

e. Perform surface blowdowns to reduce conductivity if the boiler is steaming, and to remove oil contamination. However, pH and phosphate must be kept within normal limits by chemical injection as necessary.

f. Secure the boiler as soon as possible and perform bottom blowdowns to remove sludge.

g. Blowdown or dump the boiler to reduce contamination (conductivity or oil) below normal limits.

h. Find and isolate the source of contamination. Once the source has been isolated, other boilers may be fed from that feed system if desired. Refer to the appropriate procedure for feedwater contamination, paragraphs 220-31.171 through 220-31.178.

220-31.168 Procedure Outline: MODERATE CONTAMINATION OF BOILER WATER.

Reference paragraph 220-31.118.

1. Symptoms

a. Boiler water pH, or phosphate, or conductivity changing unexpectedly or out of limits, but not severely enough to be classified as serious contamination.

b. Presence of suspended solids, abnormal color, or odor in boiler water.

2. Possible Causes

a. Moderate contamination of feedwater.

b. Moderate amounts of debris, corrosion products, or preservatives following a repair period.

3. Immediate Action

a. Sample and treat boiler water as necessary to keep pH and phosphate in limits.

4. Follow-up Actions

a. Conduct blowdowns to remove contamination. Keep pH and phosphate in limits as long as the boiler is steaming.

b. Find, isolate, and correct the source of contamination.
c. If symptoms of major contamination appear, take action in accordance with the procedure for serious boiler water contamination outlined in paragraph 220-31.167.

220-31.169 Procedure Outline: BOILER WATER CARRYOVER.

Reference paragraph 220-31.125.

1. Symptoms
   a. Visible foaming in boiler gauge glass.
   b. Erratic fluctuation of superheater outlet temperature.
   c. Audible rumbling or banging in steam lines.
   d. Boiler water conductivity greater than 2,000 µmho/cm.
   e. Detectable phosphate in condensate or drains.
   f. Visible buildup of chemical residue on steam drains, valves stems, and other fittings in superheated steam system.
2. Possible Causes
   a. High boiler water level.
   b. Improper installation or malfunction of steam drum internals.
   c. Oil in the boiler water.
   d. Boiler water conductivity in excess of limits.
   e. Excessive suspended solids in boiler water.
3. Immediate Actions
   a. Secure the boiler unless the Commanding Officer directs continued operation. If operation must be continued, minimize the firing rate.
   b. Determine if boiler water level is high, if conductivity is above limits, or if oil contamination exists.
   c. Perform surface blowdown if the boiler is still steaming. Keep pH and phosphate in limits.
4. Follow-up Actions
   a. If boiler water is contaminated, carry out the appropriate procedure for contamination of boiler water:
      (1) Serious contamination of boiler water, paragraph 220-31.167.
      (2) Moderate contamination of boiler water, paragraph 220-31.168.
   b. If boiler water level is high, carry out the procedure for boiler water high level in **NSTM Chapter 079 Volume 3, Damage Control - Engineering Casualty Control** , if installed.
   c. If boiler water is not contaminated and water level is not high but carryover is continuing, the cause is probably due to improper functioning of steam drum internals. The internals must be inspected and repaired in accordance with **NSTM Chapter 221** , the specific Boiler Technical Manual, and the Boiler Repair Manual.
   d. Flush the superheater with feedwater. Inspect superheater steamsides and steam drum internals and clean as necessary. Refer to the procedure given in NSTM Chapter 221 .

220-31.170 Procedure Outline: LEAKAGE OF BOILER WATER.

Reference paragraphs 220-31.128 and 220-31.131.

1. Symptoms
   a. Drop in boiler water conductivity, chloride, pH, and phosphate not due to blowdown or carryover.
   b. Erratic or abnormally low desuperheater outlet temperature with normal superheater outlet temperature.
   c. Unusual rise in superheater outlet temperature.
   d. Visible buildup of chemical residue at drains, valve stems, and other fittings in desuperheated steam system.
   e. Presence of boiler chemicals in desuperheated steam samples.
   f. Visible leakage from boiler handhole, manhole, or other fitting.
   g. Blowdown piping hot and pressurized with no blowdown being conducted.
   h. Abnormally high consumption of reserve feed.
2. Possible Causes
   a. Leaking desuperheater.
   b. Leaking valve, tube, handhole, manhole, or other fitting that is a boiler water pressure boundary.
3. Immediate Actions
   a. Inject chemicals as necessary to keep pH and phosphate in limits until the boiler is secured.
   b. Secure the boiler.
4. Follow-up Actions
   a. If a ruptured tube has occurred, carry out the procedure for ruptured boiler tube in **NSTM Chapter 079 Volume 3, Damage Control - Engineering Casualty Control** .
   b. As long as the boiler is steaming, keep pH and phosphate within normal limits by chemical injection as necessary.
   c. Find and repair the leak as soon as possible as discussed in paragraphs 220-31.128 and 220-31.131, in **NSTM Chapter 221** , in the specific Boiler Technical Manual, and in the Boiler Repair Manual.

220-31.171 Procedure Outline: SEAWATER CONTAMINATION OF FEEDWATER.

Reference paragraph 220-31.145.

1. Symptoms
   a. Contamination of boiler water with seawater.
   b. Salinity/conductivity reading above normal on feed and condensate system salinity/conductivity indicators.
   c. Salinity/conductivity alarm (if installed) on feed and condensate system salinity/conductivity indicators.
   d. Chloride or hardness above limit by chemical test in reserve feed, condensate, drains, or boiler feedwater.
2. Possible Causes
   a. Contaminated steam drains.
   b. Bilge water drawn into condensate pump or piping.
   c. Condenser tube leak.
   d. Contaminated makeup feed.
   e. Evaporator feed heater leakage or brine carryover to air ejectors.
3. Immediate Action
   a. Sample the steaming boilers. Carry out procedure in paragraph 220-31.167 or 220-31.168, as appropriate.

4. Follow-up Actions
   a. Attempt to find the source of contamination by salinity/conductivi ty indicator and the chemical test for chloride.
   b. Continue to sample and treat steaming boilers as necessary to keep pH and phosphate in limits.
   c. Once the source of contamination is found, isolate and repair.
5. Finding the Source of Contamination. Test the possible sources of seawater contamination for chloride. These would include the following as appropriate in the order given:
   a. Service steam drains and freshwater drains.
   b. Makeup feed.
   c. Evaporator feed heater and air ejector drains.
   d. Auxiliary gland exhaust condenser drains.
   e. Auxiliary condensate.
   f. Main condensate.

220-31.172

If salinity/conductivity readings or chemical test do not indicate the source of contamination, concentrate the samples as discussed in paragraph 220-31.148 and test again.

220-31.173 Procedure Outline: SHORE WATER CONTAMINATION OF FEEDWATER.

Reference paragraph 220-31.149.

1. Symptoms
   a. Drop in boiler water phosphate with an increase in pH. Conductivity and chloride may or may not change.
   b. High salinity/conductivity reading or alarm (if installed) on feed and condensate system salinity/conductivity indicators.
2. Possible Causes
   a. Shore source reserve feed.
   b. Contamination of ship's system with shore steam.
   c. Leakage of shore potable water into ship's steam drains.
   d. Distillation to reserve feed in a river or lake.
3. Immediate Action
   a. Sample steaming boiler(s) to determine extent of boiler water contamination. Carry out procedure in paragraph 220-31.167 or 220-31.168, as appropriate.
4. Follow-up Actions
   a. Attempt to find the source of contamination using salinity/conduct ivity indicators, and the chemical test for hardness.
   b. Sample and treat the boiler as necessary to keep pH and phosphate in limits.
   c. Once the source of contamination is found, isolate and correct it.

220-31.174 Procedure Outline: OIL CONTAMINATION OF FEEDWATER.

Reference paragraph 220-31.152.

1. Symptoms
   a. Oil contamination of boiler water.
   b. Visible oil or foaming in DFT sightglass.
   c. Visible oil or oily odor in feedwater samples.
2. Possible Causes
   a. Lubricating oil leakage into turbine glands.
   b. Oily bilge water drawn into condensate pumps, piping or steam drains.
   c. Leakage of lubricating oil purifier heater, lubricating oil settling tank heating coils, fuel oil heaters or fuel oil tank heating coils (if installed).
3. Immediate Actions
   a. If oil is visible in gage glass, conduct surface blowdown and gage glass blowdown.
   b. Check boiler water sample for oil contamination. If found, carry out the procedure in paragraph 220-31.167.
   c. Ensure bilge water is low.
4. Follow-up Action
   a. Find the source of oil contamination by sampling throughout the feed and condensate system. Isolate and repair the source when found.

220-31.175 Procedure Outline: HIGH DISSOLVED OXYGEN IN FEEDWATER.

Reference paragraph 220-31.155.

1. Symptom
   a. Feedwater dissolved oxygen concentration greater than 15 ppb.
2. Possible Causes
   a. Auxiliary exhaust system not properly lined up to DFT.
   b. Auxiliary exhaust system pressure low or unstable.
   c. Excess HP drain pressure in ships that have HP drains piped directly to the DFT shell.
   d. Malfunction of DFT condensate spray valves.
   e. Malfunction of DFT steam atomizing valve.
   f. DFT water level high enough to flood the atomizing valve.
   g. Leak in shell and tube type vent condenser.
   h. Improper venting of the DFT.
   i. Large fluctuations in condensate flow, particularly if the auxiliary exhaust augmenting and unloading valves operate sluggishly or improperly.
   j. Inadequate recirculation of feedwater during DFT warmup. (The effect of this will disappear within an hour after the plant is in full operation.)
3. Immediate Action
   a. Dissolved oxygen greater than 15 ppb is always serious. Immediate corrective action is required. If the casualty is not controlled within 8 hours of detection, the boiler must be secured.

b. Ensure the auxiliary exhaust system is properly lined up to the DFT, that auxiliary exhaust pressure is in the normal range, that the DFT water level is in the normal range, and that the DFT vent is properly lined up.

4. Follow-up Actions
   a. Attempt to find and correct the cause of the high dissolved oxygen concentration.
   b. If the cause cannot be corrected while the plant is operating, the plant should be shut down as soon as possible to minimize boiler damage and to permit correction of the cause by repairs as necessary.

220-31.176 Procedure Outline: OVERTREATMENT OF FEEDWATER WITH MORPHOLINE

1. Symptoms
   a. The emergency pH (chemical pH) will be higher than the pH measured by the pH meter.
   b. Boiler water phosphate test results will be falsely high.
   c. Calculated (theoretical) conductivity will be higher than the measured conductivity.
   d. Feedwater pH is over 9.
   e. Salinity/conductivity indicators read higher than usual.
   f. Salinity/conductivity readings will be greater than chemical test results by more than 0.04 epm.
2. Possible Causes
   a. Flow meter setting too high.
   b. Morpholine treatment not secured when the plant is secured.
   c. Light-off following hydrazine/morpholine layup.
   d. Flow meter has incorrect float installed.
3. Immediate action
   a. Secure morpholine condensate treatment system.
4. Follow-up action
   a. Sample the boiler every 4 hours until test results return to normal.
   b. Only trisodium phosphate shall be used for maintaining boiler water pH (no caustic soda) until boiler water test results indicate morpholine overtreatment has been corrected.
   c. Do not blowdown the boiler unless measured boiler water conductivity exceeds limits.
   d. After boiler water test results return to normal, resume morpholine treatment. Adjust flowrater to maintain feedwater pH between 8.6 and 9.0.

NOTE

The symptoms of silica contamination are similar to those of morpholine overtreatment. If silica contamination is suspected, test the boiler water for silica in accordance with paragraph 220-26.33.

220-31.177 Procedure Outline: SODIUM NITRITE CONTAMINATION OF BOILER WATER

1. Symptoms
   a. Feedwater chloride will be falsely high and end point may be difficult to detect.
   b. Feedwater salinity/conductivity will increase.
   c. Boiler water pH will increase.
   d. Boiler water conductivity will increase.
   e. Chloride test results for a steaming boiler are not usually affected.
2. Possible Causes
   a. Insufficient flushing of boiler and associated DFT and feed piping following sodium nitrite layup or hydrostatic testing with sodium nitrite treated water.
   b. Leakage of sodium nitrite solution into steam drain system.
3. Immediate action
   a. Follow appropriate casualty control procedures based on test results.

220-31.178 Procedure Outline: OTHER CONTAMINATION OF FEEDWATER.

Reference paragraph 220-31.158.

1. Symptoms
   a. Contamination of boiler water other than from seawater, shore water, or oil.
   b. Abnormal appearance, odor, salinity/conductivity, or other characteristics in feedwater.
2. Possible Causes
   a. Depends on nature of contamination. May include the following:
      (1) Escape of resin from the demineralizer.
      (2) Dirt, debris, corrosion products, or preservative from piping or components.
      (3) Use of feedwater from an expended shore demineralizer.
3. Immediate Action
   a. Sample the boiler(s) and carry out procedure in paragraph 220-31.167 or paragraph 220-31.168.
4. Follow-up Action
   a. Attempt to locate the source of contamination. Isolate and correct the cause when found.

220-31.179 CASUALTY CONTROL GUIDE TABLE.

Table 220-31-15 is a casualty control guide. Symptoms are tabulated as abnormalities in boiler water, steam systems, feedwater, condensate, and drain systems. For each symptom, the casualty or casualties that may result are listed together with a casualty control procedure paragraph number. This guide is provided as a training aid and convenient reminder to plant supervisors and does not relieve supervisors of the need to be thoroughly familiar with the symptoms of casualties and the immediate corrective actions.

Table 220-31-15 CASUALTY CONTROL GUIDE

Symptoms	Casualty	Procedure Paragraph
1. Boiler Water		

Table 220-31-15 CASUALTY CONTROL GUIDE - Continued

Symptoms	Casualty	Procedure Paragraph
a. pH and phosphate in free caustic region	Serious contamination of boiler water	220-31.167
b. pH less than 9.00	Serious contamination of boiler water	220-31.167
c. Phosphates less than 10 ppm	Serious contamination of boiler water	220-31.167
d. Conductivity more than 2,000 µmho/cm	1. Serious contamination of boiler water	220-31.167
	2. Carryover of boiler water	220-31.169
e. Oil in the boiler water sample	1. Serious contamination ofboiler water	220-31.167
	2. Carryover of boiler water	220-31.169
f. Foaming or other evidence ofboiler water carryover	1. Serious contamination ofboiler water	220-31.167
	2. Carryover of boiler water	220-31.169
g. Chemistry conditions out ofcontrol	Serious contamination of boiler water	220-31.167
h. Chemistry slightly out oflimits	Moderate contamination of boiler water	220-31.168
i. Suspended solids, abnormalcolor or abnormal odor inboiler water	Moderate contamination of boiler water	220-31.168
j. Drop in conductivity, chloride, pH, and phosphate	1. Carryover of boiler water	220-31.169
	2. Leakage of boiler water	220-31.170
	3. Chemical hideout	220-31.169220-31.170
k. Visible leakage from boilerfitting	Leakage of boiler water	220-31.170
2. STEAM SYSTEMS		
a. Erratic fluctuations of super-heater outlet temperature	Carryover of boiler water	220-31.169
b. Audible rumbling or bangingin steam lines	Carryover of boiler water	220-31.169
c. Buildup of chemical depositson valve packing glands	1. Carryover of boiler water	220-31.169
	2. Leakage of boiler water	220-31.170
d. Erratic or low desuperheater outlet temperature	Leakage of boiler water	220-31.170
3. FEEDWATER, CONDENSATEAND DRAINS		
a. Detectable Phosphate	1. Carryover of boiler water	220-31.169
	2. Leakage of boiler water	220-31.170
	3. Test interference frommorpholine/bicarbonate	220-31.170220-31.176
b. Abnormally high consumption of reserve feedwater	Leakage of boiler water	220-31.170
c. Salinity/conductivity readingabove normal or salinity/conductivity alarm	1. Seawater contamination offeedwater	220-31.171
	2. Shore water contamination offeedwater	220-31.173
	3. Other contamination offeedwater	220-31.173
d. Chloride above limits	1. Seawater contamination offeedwater	220-31.171
	2. Other contamination of feedwater	220-31.178
	3. Shore water contamination offeedwater	220-31.173
e. Hardness above the limit	1. Shore water contamination offeedwater	220-31.173
	2. Seawater contamination offeedwater	220-31.171
	3. Other contamination offeedwater	220-31.178
f. Detectable oil	Oil contamination of feedwater	220-31.174
g. Foaming in DFT sightglass	1. Oil contamination of feedwater	220-31.174
	2. Other contamination of feedwater	220-31.174

Table 220-31-15 CASUALTY CONTROL GUIDE - Continued

Symptoms	Casualty	Procedure Paragraph
h. Dissolved oxygen in DFT sample greater than 15 ppb	High dissolved oxygen in feedwater	220-31.175
i. Abnormal appearance, odor or other characteristic of feedwater	Other contamination of feedwater	220-31.178

220-31.180 CHEMICAL SAFETY PRECAUTIONS, HANDLING AND STORAGE.

This material is provided in Section 25.

220-31.181 FEEDWATER/BOILER SAMPLING AND TESTING

220-31.182

The changes to the feedwater/boiler water sampling and testing procedures given in Section 24 and Section 26 are provided here for coordinated phosphate and morpholine condensate treatment.

220-31.183 FEEDWATER pH TEST FOR MORPHOLINE TREATED SYSTEMS.

Phenolphthalein indicator is added to a 200 ml sample which is then titrated with nitric acid. This test indicates whether the feedwater pH is satisfactory.

NOTE

If necessary, adjust sample temperature to 25°C ±3°C (77°F ±5°F). Minimize exposure of the sample to the atmosphere.

1. Apparatus
   a. Nitric Acid reagent bottle and buret assembly.
   b. Casserole.
   c. Stirring rod.
   d. Graduated cylinder, 100 ml.
2. Reagents
   a. Nitric acid reagent, 0.05 N (prepared from 50 ml of 1.0 N nitric acid stock solution, diluted to 1,000 ml with distilled water, refer to paragraph 220-24.47).
   b. Phenolphthalein indicator (2 level dippers of phenolphthalein dissolved in 25 ml of distilled water and 25 ml of isopropyl alcohol, refer to paragraph 220-24.49).
   c. Distilled water.
3. Interferences
   a. Absorption of carbon dioxide from the atmosphere lowers pH. Refer to paragraph 220-31.203.
4. Procedure

a. Rinse the casserole and stirring rod with distilled water.

b. Rinse the 100 ml graduated cylinder with distilled water and then with some of the water to be tested.

c. Measure exactly 200 ml of the sample into the casserole.

d. Add 2 to 3 drops of phenolphthalein indicator.

(1) If the sample remains colorless, pH is less than 8.2. Record the result in the log as less than 8.2.

(2) If the sample turns pink, continue to step e.

e. Rezero the buret and add 0.05 N nitric acid reagent to the sample dropwise, while stirring, until the sample is colorless.

f. Read the buret and record the result in the Feedwater Chemistry Worksheet/Log.

(1) If the buret reading is 0.1 ml, pH is satisfactory. Record the result in the log as 8.6 to 9.0.

(2) If the buret reading is greater than 0.1 ml, excess morpholine is present. Record the result in the log as greater than 9.0.

5. Range of Error: the range of error of the test is ±0.3 pH unit. In ships with morpholine condensate treatment, feedwater pH is controlled by adjusting the morpholine flow rate. Overtreatment with morpholine can occur when the flow meter setting is too high, when the incorrect float is used, or when the morpholine treatment system is not secured when the plant is secured. Excess morpholine will also be present following light-off of a boiler under hydrazine/morpholine layup. Morpholine overtreatment is indicated by feedwater pH above 9. The salinity/conductivity indicators will also read higher than usual, and the comparison test results will show the indicator reading to be greater than the chemical test result by more than 0.04 epm.

220-31.184 pH METER EQUIPMENT AND TESTING.

The pH test equipment consists of a combination pH/reference electrode, a pH meter, an adapter, buffers, potassium chloride, a thermometer calibrated in degrees Celsius, and plastic jars. The electrode and meter form a high-resistance, low-current system that gives reliable values for pH. Certain characteristics and techniques of pH measurement must be understood and followed. Once a pH meter is set up it should not be disconnected from line power unless the equipment will not be used for an extended time period (such as a week or more). If the Orion Model 601N pH meter has been disconnected, allow it to warm up for 1/2 hour prior to use. The Model SA 720 pH meter does not require a warm up period. The power source must be grounded. This equipment is user calibrated. Refer to paragraph 220-24.43. The electrical characteristics of the electrode are temperature dependent. Additionally, pH is dependent on sample temperature. The temperature compensator on a pH meter does not correct pH for the temperature of the solution being measured. It corrects for the temperature-affected electrical characteristics of the electrode. The combination pH/reference electrode is a galvanic cell actually containing two electrodes. The potential of the reference electrode is constant and does not depend on the solution being measured. The potential of the pH electrode varies depending on the hydrogen ion activity (pH) of the sample in which the combination electrode is immersed. Leads from the electrode are connected to the pH meter which measures the potential difference between the two electrodes, giving a readout directly in pH.

220-31.185 MODEL 601N pH METER PROCEDURES.

Most problems in pH measurement result from electrode or electrical contact deficiencies rather than from the meter itself. When initially received or when meter operation is suspected, check the meter as follows:

1. Turn the function switch to the standby (STDBY) position.

2. Attach the power cord to the meter and plug it into a 110-115 volts grounded power source. An illuminated

red dot in the middle of the display will indicate that the meter is being supplied with power. Allow at least 30 minutes for warmup. If, for any reason, the power is interrupted, allow at least 30 minutes warmup time prior to a standardization or a pH measurement.

3. Set the % SLOPE control to 100 percent.
4. Check the meter electronics as follows:
   a. Connect the shorting strap across the INPUT and REF jacks.
   b. Turn the function switch to the pH position.
   c. Turn the CALIB control knob clockwise until a maximum reading is obtained and note the reading. (A slight increased resistance to control knob turning will be noticed as the maximum reading is obtained.)
   d. Turn the CALIB control knob counterclockwise until a minimum reading is obtained and note the reading. (Again, a slight resistance to turning will be noticed as the minimum reading is obtained.)
   e. The meter is malfunctioning if the difference between the two readings is not at least 7.00 pH units.
5. Turn the function switch to the ISO position. The meter display should show 7.00. If necessary, turn the ISO ADJ on the rear panel until a display of 7.00 is obtained. (The new meter, as received, will read about 7.00. Turn the ISO ADJ until a reading of 7.00 is obtained.)
6. Turn the function switch to STDBY.

220-31.186 MODEL SA 720 pH METER PROCEDURES.

The Orion Model 601N pH meter is no longer being manufactured and, on an interim basis, is being replaced by the automated Orion Model SA 720. Procedures for initiating use of the SA 720 follow:

1. Connect AC line converter to rear panel (power) of meter and grounded power source.
2. Slide power switch (next to digital display on front panel) up to the ON position.
3. Attach BNC Shorting Plug (suspended on rear panel) to meter INPUT connection. Slide connector onto input jack, pushing in and turning clockwise into position.
4. Slide mode switch on front panel to REL MV. The SAMPLE LED will light. Press SAMPLE. Display should read 0.0 ±0.2.
5. Slide mode switch to TEMP. The SAMPLE LED should light. The display should read 25.0. If not, scroll (raise or lower the displayed value) using ↑ and ↓ keys, until 25.0 is displayed and press ENTER.
6. Slide mode switch to pH. The SAMPLE LED will light. If not, press SAMPLE. Press ISO. Observe the ISO LED lights. The SAMPLE LED will go off. The displayed isopotential value should be 7.00. If 7.00 is not displayed, scroll using ↑ and ↓ keys until 7.00 is displayed and press ENTER.
7. Press SLOPE. The SLOPE LED will light. A value of 100.0 should be displayed. If 100.0 is not displayed, scroll until 100.0 is displayed and press ENTER.
8. Press SAMPLE. The SAMPLE LED will light, then a steady reading of 7.00 should be displayed. If not, press CAL, CAL 1 LED should light. Scroll until 7.00 is displayed and press ENTER, CAL 2 LED should light. Press SAMPLE. SAMPLE LED will light and a reading of 7.00 should be displayed.
9. Slide mode switch to CONC. The SAMPLE LED should light. If not, press SAMPLE. Press ISO. The ISO LED will light and SAMPLE LED should go off. A value of 1.00 should be displayed. If 1.00 is not displayed, scroll until 1.00 is displayed and press ENTER.
10. Press SLOPE. The SLOPE LED will light. A value of 59.2 should be displayed. If 59.2 is not displayed, scroll until 59.2 is displayed and press ENTER.

11. Press SAMPLE. The SAMPLE LED should light, then a steady reading of 1.0 ±0.1 should be displayed. If not, press CAL, CAL 1 LED should light. Scroll in 1.0 and press ENTER, CAL 2 LED should light. Press SAMPLE. The SAMPLE LED will light and a steady reading of 1.0 ±0.1 should be displayed.

12. Disconnect the shorting plug.

13. Attach pH electrode connector to the cylindrical end of the adaptor using the thumbscrew. Attach adaptor connector to the meter INPUT jack (where shorting plug was previously connected) by pushing in and turning clockwise to lock into position. Connect electrode pin tip reference connector to the meter reference INPUT jack. The small female connector on the adaptor is not used.

14. After successful completion of steps 1-13, the meter is ready for calibration.

220-31.187 Electrode.

Carefully remove the tape from the vent-hole and then the protective plastic end cap from a new or stored electrode, rinse the tip with distilled water, shake off excess water, and place the electrode in a dropping bottle that is half filled with potassium chloride solution. Attach the electrode to the Model 601N pH meter by plugging the two electrode connectors into the INPUT and REF jacks on the rear panel of the meter. In order to attach the pH electrode to the Model SA 720 pH meter, an adapter must be used. The pH electrode connector must be attached to the cylindrical end of the adapter. Attach the adapter connector to the meter INPUT jack by pushing in and turning clockwise. Connect electrode pin tip reference connector to the meter reference INPUT jack.

220-31.188

The tip of the pH electrode contains the pH sensing element. This tip is a glass bulb membrane that is less than 0.1 mm thick (0.004 inch). It is fragile. Dirt, grease, and scratches on this glass membrane will interfere in pH measurement. Proper functioning of the electrode is determined on a daily basis by standardizing the meter between pH 7 and pH 10 with buffers. When the slope adjustment falls below 92 percent, loss of electrode sensitivity is indicated. Very careful and gentle wiping of the glass surface using a small, soft artist's brush, dipped in distilled water, may restore the electrode. Oil or grease may be removed by isopropyl alcohol rinsing, but the electrode must be stored overnight in potassium chloride solution before reuse. If the slope still falls below 92 percent but the meter can be standardized between pH 7 and pH 10, use the electrode until a replacement is obtained. A shipyard laboratory may be able to clean the electrode by immersion of the tip in 0.1 N hydrochloric acid. (Do not use nitric acid stock or reagent solutions.)

220-31.189

Electrode characteristics slowly change because of normal chemical and mechanical attack of the bulb surface. As above, deterioration is indicated by less than 92 percent slope during standardization. This is another reason that standardization is performed daily. Inability to standardize or too low a percent slope usually means that the electrode is dirty or deteriorated. If the pH meter gives the same reading or no reading with both standardization buffers, the glass membrane is probably cracked, making the electrode useless. Electrodes normally last from 1 to 2 years.

220-31.190

Any time an electrode is changed, restandardization is necessary because no two electrodes have exactly the same composition and fabrication characteristics.

220-31.191

Keep the glass tip of the electrode wet with potassium chloride solution. The electrode will not operate if the external surface of the glass is dehydrated. Function can be restored by overnight soaking of the tip in potassium chloride solution.

220-31.192

If the electrode will not be used for an extended period, insert a small piece of cotton into the protective end cap, rinse the electrode with distilled water, shake off excess water, moisten the cotton with potassium chloride solution, gently slide the cap over the tip, cover the cap venthole with a small piece of tape, wrap the electrode, and store it in a suitable container. Do not tape the cap to the electrode body.

220-31.193

When performing a pH measurement with the Model 601N pH meter, never remove the electrode from the solution unless the function switch is in the STD BY position. Doing so eventually causes electrode polarization (slow response and reversed readings) and permanent damage. The Model SA 720 pH meter does not have a STDBY position. When performing a pH measurement with the Model SA 720 pH meter, the electrode can be removed from the solution when the SAMPLE LED is lit. Do not connect and disconnect the electrode from the meter more than is necessary. Leave the meter plugged in and in the STDBY position (Model 601N) or with the SAMPLE LED lit (Model SA 720) unless it will not be used for an extended period such as a week or more.

220-31.194

The electrode bulb and lower portion of the electrode body are always rinsed thoroughly with distilled water when removed from a buffer or sample. Thorough rinsing after removal from a buffer solution is particularly important since a trace of buffer contamination will change the pH of the sample. Rinsing with a sample is required prior to immersion in a sample (buffer or boiler water). The solution is stirred gently with the electrode to ensure a homogeneous solution contact over the membrane surface.

220-31.195

Cable connections must be clean and dry. Dirt and poor electrical contact to the meter will result in drifting or erratic response. Movement of electrode cable connections should be avoided, as should looping and twisting of the electrode cable itself.

220-31.196

The electrode in the plastic jar tends to tip over. Fabrication of a stable holding device will be necessary for most ships. A wooden box, made of 3/8-inch plywood, 10-1/4 inches long, 3-3/4 inches wide, 3 inches high, should be used. Cut three holes into the top of the box, each 2-3/4 inches diameter and 1/2 inch from each other and from the sides. Avoid metal boxes since static electricity may cause erratic electrode response.

220-31.197 BUFFERS.

A buffer is a relatively concentrated solution that resists changes in pH even when an acid or an alkali is added to it. Because of this property, buffers are ideally suited to standardization of a pH meter. The pH response is rapid and the meter will stabilize quickly. The pH standard buffers are certified for accuracy and are used in standardizing the pH equipment. Whenever pH measurements are to be performed, daily meter standardization is required.

220-31.198

The pH of buffers does change with temperature, so to minimize error, standardization must be accomplished when the buffer temperature is 25°C ±3°C (77°F ±5°F). Heat or cool the buffer by immersion of the capped plastic jar in warm or cool water as needed.

220-31.199

Whenever the electrode is removed from a buffer solution, ensure that the electrode tip is rinsed well with distilled water. Slight buffer contamination of boiler water will change the pH of the sample.

220-31.200 SAMPLES.

Never filter a sample prior to measuring pH by a pH meter. Carbon dioxide absorption from the atmosphere severely lowers pH.

220-31.201

pH changes as temperature changes; therefore, pH is always determined at or corrected to a standard temperature of 25°C (77°F). The pH of 0 to 14, with 7 signifying neutral water, is valid only at 25°C (77°F). For example, neutral water has a pH of 7 at 25°C (77°F), but neutral water has a pH of 6.3 at 60°C (140°F). Sample temperature restrictions or corrections must be observed for measurements to have meaning. The pH meter temperature compensator does not correct pH for the sample temperature. (Refer to paragraph 220-31.184.)

220-31.202

Preferably, boiler water should be cooled to 25°C ±3°C (77°F ±5°F); however, adjustment to this temperature range is not required.

220-31.203

All feedwater and boiler water samples should be protected from atmospheric exposure because carbon dioxide will dissolve in the sample and lower pH. Collect a full bottle of sample and determine pH prior to performing other tests.

220-31.204

Electrode response is slower for boiler water samples than for buffers. Wait for the meter display to stabilize before taking a reading (this should take 3 minutes or less). The boiler water temperature correction is added to or subtracted from the displayed reading and the corrected value is recorded.

220-31.205

When a bimetallic thermometer is first received, or if operation is suspect, its function should be checked by immersion of the stem in an ice water bath. If the dial indicator is not 0°C (32°F), replace the thermometer.

220-31.206 Preparation of Potassium Chloride Solution (3-Molar).

The potassium chloride solution is used for storage of the pH electrodes.

1. Rinse a quart plastic bottle and cap with distilled water.

2. Transfer the contents of two jars of potassium chloride to the quart plastic bottle (1/2 pound of potassium chloride total).

3. Add distilled water to the shoulder of the plastic bottle.

4. Cap the bottle and shake to dissolve the potassium chloride. Label the bottle 3-Molar Potassium Chloride.

5. Half fill an indicator dropping bottle with the potassium chloride solution. Store the electrode in the solution between measurements.

NOTE

Replace the 3-Molar Potassium Chloride electrode storage solution in the indicator dropping bottle weekly. Mark the date of replacement on the bottle.

220-31.207 pH SYSTEM MALFUNCTION.

Daily standardization of the pH meter with buffers will indicate whether it is performing properly. Standardization itself can be faulty because of improper mixing of the buffer, improper buffer temperature, poor quality of the buffer, or failure to follow the procedure for standardizing the meter. If standardization is properly performed with good quality buffers, but the meter fails to respond properly, the trouble is most likely in the electrode. Replace the electrode and try again. Ensure that the electrode is always handled and stored properly as specified in paragraphs 220-31.187 through 220-31.196; otherwise, its performance will deteriorate. Performance of the meter electronics can be checked by following the procedure outlined for initial setup of the meter in paragraphs 220-31.185 and 220-31.186. If the meter is properly standardized, and the procedures for pH measurement given in paragraphs 220-31.209, 220-31.210, 220-31.211, 220-31.212, 220-31.213 and 220-31.214 are followed meticulously, then reliable, accurate, repeatable pH readings should be obtained. Pitfalls that can reduce the accuracy of measurement with a properly standardized pH meter are:

1. Failure to measure pH first, as soon as the sample is uncapped, or failure to completely fill and cap the sample bottle when drawing the sample. This is because alkaline water, such as boiler water, absorbs carbon dioxide from the air and becomes more acidic the longer it is exposed to the air.

2. Excessive or violent stirring of the sample, since this increases absorption of carbon dioxide from the air.

3. Failure to thoroughly rinse the electrode or the container before measuring the sample, causing contamination from a previous sample. This is especially a problem if it is buffer solution that contaminates the sample, since even a tiny amount of buffer solution will seriously affect sample pH.

4. Failure to set temperature compensator on the meter to the actual sample temperature, because the characteristics of the electrode change with temperature.

5. Failure to adjust feedwater temperature to 25°C ±3°C (77°F ± 5°F), or failure to apply the boiler water correction given in Table 220-31-16 to the pH meter reading. This is because the pH of the sample actually changes with temperature, quite independent of the change in electrical characteristics of the electrode. The properly operated pH meter measures the actual pH at whatever the temperature happens to be. For uniformity, boiler water and feedwater pH limits are specified at 25°C (77°F). Sample temperature must be adjusted to that value, or in the case of boiler water only, a correction is applied to the measured pH.

6. Failure to store the electrode in potassium chloride solution when idle. This will lead to reduction in sensitivity and sluggish response.

7. Failure to allow the meter display to stabilize before making a reading.

8. Failure to turn the meter function switch (Model 601N) to standby before removing the electrode from solution. This will cause deterioration in electrode performance.
9. Inadvertently touching the Calibration or Slope knob after the meter (Model 601N) is standardized. Masking tape put over those knobs after standardization is often a helpful reminder.
10. Failure to allow the meter (Model 601N) to warm up properly or to standardize it when it is reenergized after having been deenergized for any reason.

220-31.208

If for some reason the pH meter cannot be used or will not give reliable indication, pH can be measured well enough to permit continued plant operation by using the emergency methods of pH measurement described in paragraph 220-31.215.

220-31.209 TWO POINT pH METER STANDARDIZATION FOR MODEL 601N.

The pH meter is standardized on a daily basis when pH measurements are to be made. Standardization is performed by adjusting the meter to read the correct value when the electrode is placed in two certified buffer solutions whose temperature is 25°C ±3°C (77°F ±5°F).

1. Apparatus
   a. Meter, digital pH, requires 110-115 volts power supply.
   b. pH electrode, gel-filled, combination, connected to the pH meter.
   c. Thermometer, metal, dial type, 0°C to 100°C (32°F to 212°F).
   d. Jars, plastic, wide mouth, screw capped (2) (one marked and used for pH 7 buffer only, the other marked and used for pH 10 buffer only).
   e. Graduated cylinder, 100 ml.
2. Reagents
   a. Buffer capsule, pH 7.00 ±0.05 at 25°C (77°F).
   b. Buffer capsule, pH 10.00 ±0.05 at 25°C (77°F).
   c. A 3-Molar potassium chloride solution, 1/2 pound of potassium chloride per quart of distilled water. Refer to paragraph 220-31.206 for solution preparation.
   d. Distilled water.
3. Procedure

NOTE

Daily standardization is required when pH measurements are to be made. Restandardize any time power to the meter is interrupted. Do not filter any solution prior to pH measurement. Assure that the function switch is in the STDBY position and that the meter has been warmed up for 30 minutes. The temperature of both buffer solutions shall be adjusted to 25°C ±3°C (77°F ±5°F). Never remove the electrode from the solution unless the function switch is in the STDBY position.

a. Rinse both plastic jars and caps with distilled water. Shake out excess water.

b. Rinse a 100 ml graduated cylinder with distilled water. Measure 100 ml of distilled water into each plastic jar. (Use distillate, not condensate.) Empty the contents of a pH 7 buffer capsule into the pH 7 jar. Empty the contents of a pH 10 buffer capsule into the pH 10 jar. Cap the jars and swirl until the buffers are dissolved.

c. Rinse the thermometer and electrode with distilled water and then with a small amount of the pH 7 buffer solution. Place the thermometer and electrode into the jar and measure the buffer temperature.

d. Set the TEMP control to the temperature of the pH 7 buffer solution. Remove the thermometer and rinse it with distilled water.

e. Use the electrode as a stirring rod and stir the pH 7 buffer solution for 3 or 4 seconds. Then allow the electrode to rest against the side of the jar with the tip in the solution.

f. Turn the function switch to the pH position.

g. Adjust the CALIB control knob to obtain a pH reading of 7.00 on the digital display.

h. Turn the function switch to the STDBY position. Remove the electrode and rinse it with distilled water. Shake off excess water.

NOTE

Do not touch the CALIB control knob until another standardization is needed. The meter must be restandardized if the knob is inadvertently turned.

i. Rinse the thermometer and electrode again with distilled water and then with a small amount of the pH 10 buffer solution. Place the thermometer and electrode in the jar and measure the buffer temperature.

j. Set the TEMP control to the temperature of the pH 10 buffer. Remove the thermometer and rinse it with distilled water.

k. Use the electrode as a stirring rod and stir the pH 10 buffer for 3 or 4 seconds. Then allow the electrode to rest against the side of the jar with the tip in the solution.

l. Turn the function switch to the pH position.

m. Adjust the % SLOPE control knob to obtain a reading of 10.00 on the digital display. Record the % SLOPE reading in the boiler water log. Refer to paragraphs 220-31.189 and 220-31.190.

NOTE

Do not touch the % SLOPE control knob until another standardization is needed. The meter must be restandardized if the knob is inadvertently turned.

n. Turn the function switch to the STDBY position. Remove the electrode and rinse it with distilled water. Shake off the excess water and rerinse the electrode. Store the electrode in potassium chloride solution contained in a dropping bottle. Replace the used potassium chloride solution weekly.

o. Discard the pH 7 and pH 10 buffer solutions. Thoroughly rinse the jars and caps with tap water and then with distilled water. (A tap water rinse is used because the buffer solutions are difficult to flush from the jars. The distilled water then rinses away the tap water.)

p. Record the time of standardization in the boiler water logs for all steaming boilers.

Table 220-31-16 TEMPERATURE CORRECTION FOR BOILER WATER PH

SAMPLE TEMPERATURE			SAMPLE TEMPERATURE		
°C	**°F**	**Correction**	**°C**	**°F**	**Correction**
15	59	-0.20	27	80-81	+0.04

Table 220-31-16 TEMPERATURE CORRECTION FOR BOILER WATER

PH - Continued

SAMPLE TEMPERATURE			SAMPLE TEMPERATURE		
°C	**°F**	**Correction**	**°C**	**°F**	**Correction**
16	60-61	-0.18	28	82-83	+0.06
17	62-63	-0.16	29	84-85	+0.08
18	64-65	-0.14	30	86	+0.10
19	66-67	-0.12	31	87-88	+0.12
20	68	-0.10	32	89-90	+0.14
21	69-70	-0.08	33	91-92	+0.16
22	71-72	-0.06	34	93-94	+0.18
23	73-74	-0.04	35	95	+0.20
24	75-76	-0.02	36	96-97	+0.22
25	77	-0.00	37	98-99	+0.24
26	78-79	+0.02	38	100	+0.26

220-31.210 TWO POINT pH METER STANDARDIZATION FOR MODEL SA 720.

The pH meter is Standardized on a daily basis when pH measurements are to be made. Standardization is performed by adjusting the meter to read the correct value when the electrode is placed in two certified buffer solutions whose temperature is 25°C ±3°C (77°F ±5°F).

1. Apparatus
   a. Meter, SA 720 digital pH, requires 110 or 220 volt power supply. Meter may also be battery operated using six 1.5 V AA non-rechargeable alkaline batteries.
   b. Adaptor, U.S. Standard to BNC connector. Its function is to connect the electrode probe to the meter. The small female connector on the adaptor is not used.
   c. pH electrode, gel-filled, combination, connected to the adaptor.
   d. Jars, plastic, wide mouth, screw capped (2) (one marked and used for pH 7 buffer only, the other marked for pH 10 buffer only).
   e. Graduated cylinder, 100 ml.
   f. Thermometer, metal, dial type, 0° to 100°C (32° to 212°F).
2. Reagents
   a. Buffer capsule, pH 7.00 ±.05 at 25°C (77°F)
   b. Buffer capsule, pH 10.00 ±.05 at 25°C (77°F)
   c. A 3-Molar potassium chloride solution, 1/2 pound of potassium chloride per quart of distilled water. Refer to paragraph 220-31.206 for solution preparation.
   d. Distilled water.
3. Procedure

NOTE

Daily standardization is required when pH measurements are to be made. Restandardize any time power to the meter is interrupted. Do not filter any solution prior to pH measurement. The temperature of both buffer solutions shall be adjusted to 25°C ±3°C (77°F ±5°F). Warm up time for the Orion Model SA 720 is not required.

a. Rinse both plastic jars and caps with distilled water. Shake out excess water.
b. Rinse a 100 ml graduated cylinder with distilled water. Measure 100 ml of distilled water into each plastic jar. (Use distillate, not condensate.) Empty the contents of a pH 7 buffer capsule into the pH 7 jar. Empty the contents of a pH 10 buffer capsule into the pH 10 jar. Cap the jars and swirl until the buffers are dissolved.
c. Rinse the thermometer and electrode with distilled water and then with a small amount of the pH 7 buffer solution. Place the thermometer and electrode into the jar and measure the buffer temperature.
d. Slide mode switch to TEMP. Adjust TEMP readout using scroll ↑ and ↓ to the temperature of the pH 7 buffer solution. Press ENTER. Remove thermometer and rinse it with distilled water.
e. Use the electrode as a stirring rod and stir the pH buffer solution for 3 or 4 seconds. Then allow the electrode to rest against the jar with the tip in the solution.
f. Slide mode switch to pH. Press SAMPLE repeatedly to set the number of decimal places to two. (Number of digits to the right of the decimal.)
g. Press CAL. The CAL 1 LED will light for pH 7 buffer. Wait for READY LED to light then press ENTER. The CAL 2 LED will light indicating the meter is ready for the second buffer.
h. Rinse electrode and thermometer with distilled water and then with a small amount of the pH 10 buffer solution. Place the thermometer and electrode into the jar and measure the buffer temperature.
i. Slide mode switch to TEMP. Adjust temp readout using scroll ↑ and ↓ to the temperature of the pH 10 buffer solution. Press ENTER. Remove thermometer and rinse it with distilled water.
j. Use the electrode as a stirring rod and stir the pH 10 buffer solution for 3 or 4 seconds. Then allow the electrode to rest against the side of the jar with the tip in the solution.
k. Slide mode switch to pH. Wait for READY LED to light then press ENTER.
l. Press SLOPE key. Read the value from the display. Record this % slope reading in the boiler water log. Refer to paragraphs 220-31.189 and 220-31.190.
m. Press SAMPLE key. The SAMPLE LED will light. Meter is now ready for sample measurements. Remove the electrode and rinse it with distilled water. Shake off the excess water and rerinse the electrode. Store the electrode in potassium chloride solution contained in a dropping bottle. Replace the used potassium chloride solution weekly.
n. Discard the pH 7 and 10 buffer solutions. Thoroughly rinse the jars and caps with tap water and then with distilled water. (A tap water rinse is used because the alkaline buffer solutions are difficult to flush from the jars. The distilled water then rinses away the tap water.)
o. Record the time of standardization in the boiler water logs for all steaming boilers.

220-31.211 Single Point pH Meter Standardization for Model 601N.

If one of the buffers used in the two point standardization is defective, the pH meter may be standardized with only one buffer using the following procedure:

1. Apparatus
   a. Meter, digital pH, requires 110-115 volts power supply.
   b. pH electrode, gel-filled, combination, connected to the pH meter.
   c. Thermometer, metal, dial type, 0°C to 100°C (32°F to 212°F).

d. Jar, plastic, wide mouth, screw capped (marked and used for buffer only).
e. Graduated cylinder, 100 ml.

2. Reagents
   a. Buffer capsule.
   b. A 3-Molar potassium chloride solution, 1/2 pound of potassium chloride per quart of distilled water. Refer to paragraph 220-31.206 for solution preparation.
   c. Distilled water.

3. Procedure

NOTE

Daily standardization is required when pH measurements are to be made. Restandardize any time power to the meter is interrupted. Do not filter any solution prior to pH measurement. Assure that the function switch is in the STDBY position and that the meter has been warmed up for 30 minutes. The temperature of the buffer solutions shall be adjusted to 25°C ±3°C (77°F ±5°F). Never remove the electrode from the solution unless the function switch is in the STDBY position.

a. Rinse the jar and cap with distilled water. Shake out excess water.
b. Rinse a 100 ml graduated cylinder with distilled water. Measure 100 ml of distilled water into the plastic jar. (Use distillate, not condensate.) Empty the contents of the buffer capsule into the jar. Cap the jar and swirl until the buffer is dissolved.
c. Set the % SLOPE control knob to 100%.
d. Rinse the thermometer and electrode with distilled water and then with a small amount of the buffer solution. Place the thermometer and electrode into the jar and measure the buffer temperature.
e. Set the TEMP control to the temperature of the buffer solution. Remove the thermometer and rinse it with distilled water.
f. Use the electrode as a stirring rod and stir the buffer solution for 3 or 4 seconds. Then allow the electrode to rest against the side of the jar with the tip in the solution.
g. Turn the function switch to the pH position.
h. Adjust the CALIB control knob to obtain the pH of the buffer in use (7.00 or 10.00 as applicable) on the digital display.
i. Turn the function switch to the STDBY position. Remove the electrode and rinse it with distilled water. Shake off excess water and rerinse the electrode. Store the electrode in potassium chloride solution contained in a dropping bottle. Replace the used potassium chloride solution weekly.

NOTE

Do not touch the CALIB control knob until another standardization is needed. The meter must be recalibrated if the knob is inadvertently turned.

j. Discard the buffer solution. Thoroughly rinse the jar and cap with tap water and then distilled water. (A tap water rinse is used because buffer solutions are difficult to flush from the jar. The distilled water then rinses away the tap water.)

k. Record 100% in the % SLOPE column and record the time of standardization in the boiler water logs for all steaming boilers.

220-31.212 ONE POINT pH METER STANDARDIZATION FOR MODEL SA 720.

If one of the buffers used in the two point calibration is defective the pH meter may be calibrated with only one buffer using the following procedure:

1. Apparatus
   a. Meter, SA 720 digital pH, requires 110 or 220 volt power supply. Meter may also be battery operated using six 1.5V AA non-rechargeable alkaline batteries.
   b. Adaptor, U.S. Standard to BNC connector. Its function is to connect the electrode probe to the meter.
   c. pH electrode, gel-filled, combination, connected to the adaptor.
   d. Thermometer, metal, dial type, 0° to 100°C (32° to 212°F).
   e. Jar, plastic, wide mouth, screw capped (marked and used for buffer only).
   f. Graduated cylinder, 100 ml
2. Reagents
   a. Buffer capsule.
   b. A 3-Molar potassium chloride solution, 1/2 pound of potassium chloride per quart of distilled water. Refer to paragraph 220-31.206 for solution preparation.
   c. Distilled water.
3. Procedure

NOTE

Daily standardization is required when pH measurements are to be made. Restandardize any time power to the meter is interrupted. Do not filter any solution prior to pH measurement. The temperature of the buffer solutions shall be adjusted to 25°C ±3°C (77°F ±5°F). Warm up time is not required for the model SA 720.

a. Rinse the jar and cap with distilled water. Shake out excess water.
b. Rinse a 100 ml graduated cylinder with distilled water. Measure 100 ml of distilled water into the plastic jar. (Use distillate, not condensate.) Empty the contents of the buffer capsule into the jar. Cap the jar and swirl until the buffer is dissolved. Rinse the thermometer and electrode with distilled water and then with a small amount of the buffer solution. Place the thermometer and electrode into the jar and measure the buffer temperature.
c. Slide mode switch to TEMP. Adjust TEMP readout using scroll ↑ and ↓ to the temperature of the buffer solution. Press ENTER. Slide mode switch to pH. Remove thermometer and rinse it with distilled water.
d. Press SLOPE. Adjust slope reading to 100.0 using scroll ↑ and ↓. Press ENTER.
e. Use the electrode as a stirring rod and stir the buffer for 3 or 4 seconds. Then allow the electrode to rest against the side of the jar with the tip in the solution.
f. Press SAMPLE key repeatedly to set the decimal places to two (number of digits to the right of the decimal). Press CAL. The CAL 1 LED will light.
g. Wait for READY LED to light. Press ENTER. The CAL 2 LED will light.

h. Press SAMPLE key. The SAMPLE LED will light. Meter is now ready for sample measurements. Remove the electrode and rinse it with distilled water. Shake off the excess water and rerinse the electrode. Store the electrode in potassium chloride solution contained in a dropping bottle. Replace the used potassium chloride solution weekly.

i. Discard the buffer solution. Thoroughly rinse the jar and cap with tap water and then distilled water. (A tap water rinse is used because buffer solution is difficult to flush from the jar. The distilled water then rinses away the tap water.)

j. Record 100% in the % slope column and record the time of standardization in the boiler water logs for all steaming boilers.

220-31.213 BOILER WATER PH TEST USING MODEL 601N pH METER.

The pH of boiler water is determined by placing the pH electrode into the sample, reading the pH indicated on the meter display, and correcting the indicated pH for the sample temperature in order to obtain the actual pH of the boiler water.

1. Apparatus
   a. Meter, digital pH, requires 110-115 volts power supply.
   b. pH electrode, gel-filled, combination, connected to the pH meter.
   c. Thermometer, metal, dial type, 0°C to 100°C
   d. Jar, plastic, wide-mouth (marked and used for sample only).
2. Reagents
   a. A 3-Molar potassium chloride solution, 1/2 pound of potassium chloride per quart of distilled water. Refer to paragraph 220-31.206) for solution preparation.
   b. Distilled water.
3. Interferences
   a. Absorption of carbon dioxide from the atmosphere causes pH to decrease. Refer to paragraph 220-31.203.
   b. Oil and suspended matter may coat the electrode making it inoperable.
   c. The pH measurement is most accurate when the sample temperature is 25°C (77°F), refer to paragraph 220-31.184. Cold water will give high results while hot water will give low results. Sample temperature should therefore be between 22°C to 28°C (72°F to 82°F).
4. Procedure
   a. Daily Standardization. The meter standardization procedure is listed in paragraphs 220-31.209 and 220-31.211. Only one daily standardization is needed when the pH measurements are to be made.
   b. Measurement of Boiler Water pH.

NOTE

Do not filter any solution prior to pH measurement. Assure that the function switch is in the STDBY position and that the meter has been warmed up for 1/2 hour. Assure that the meter has been standardized for the day. Never remove the electrode from the solution unless the function switch is in the STDBY position.

(1) Rinse the thermometer, electrode, and the plastic jar with distilled water and then with the sample. Pour sample into the jar until it is approximately 1/2 full.

(2) Measure the temperature of the boiler water, record the temperature in the log, and set the TEMP control to the sample temperature. Remove the thermometer and rinse it with distilled water.

(3) Use the electrode to stir the sample for 3 or 4 seconds. Then allow the electrode to rest against the side of the jar with the tip in the solution.

(4) Turn the function switch to the pH position.

(5) After the reading has stabilized, record the reading in the log. Use Table 220-31-16 to correct the pH shown on the meter display. Look up the correction for the boiler water sample temperature and record the correction in the log. Add the correction to or subtract it from the displayed pH reading. Record the corrected value in the log. For example:

(6) Return the function switch to the STDBY position.

(7) Remove the electrode and rinse it with distilled water. Store it in potassium chloride solution between measurements and replace the used potassium chloride solution weekly.

(8) Rinse the sample jar with distilled water.

NOTE

Boiler water treatment action is based on the corrected pH that is recorded in the log. It is not based on the reading showing on the meter display unless the sample temperature is 25°C (77°F).

5. Range of Error: the range of error of the test is ±0.10 pH units.

Sample Calculation for pH Temperature Correction:

Boiler Water Temperature		**Meter Reading**	**Correction**	**Corrected pH Recorded in the Log**
°C	**°F**			
20	68	10.20	-0.10	10.10
24	75	10.20	-0.02	10.18
25	77	10.20	0.00	10.20
31	88	10.20	+0.12	10.32
34	93	10.20	+0.18	10.38

220-31.214 BOILER WATER PH TEST USING MODEL SA 720 pH METER.

The pH of boiler water is determined by placing the pH electrode into the sample, reading the pH indicated on the meter display, and correcting the indicated pH for the sample temperature in order to obtain the actual pH of the boiler water.

1. Apparatus
   a. Meter, SA 720 digital pH, requires 110 or 220 volt power supply. Meter may also be battery operated using six 1.5 V AA non-rechargeable alkaline batteries.
   b. Adaptor, U.S. Standard to BNC connector. Its function is to connect the electrode probe to the meter.
   c. pH electrode, gel-filled, combination, connected to the adaptor.
   d. Jar, plastic, wide-mouth (marked and used for sample only).
   e. Thermometer, metal, dial type, 0° to 100°C (32° to 212°F).

2. Reagents

a. A 3-Molar potassium chloride solution, 1/2 pound of potassium chloride per quart of distilled water. Refer to paragraph 220-31.206 for solution preparation.

b. Distilled water.

3. Interferences

a. Absorption of carbon dioxide from the atmosphere causes pH to decrease. Refer to paragraph 220-31.203.

b. Oil and suspended matter may coat the electrode making it inoperable.

c. Though a temperature correction is applied, the pH measurement is more accurate if the sample temperature is between 22°C (72°F) and 28°C (82°F). Cold water tends to give high results while hot water tends to give low results.

4. Procedure

a. Daily Calibration. The meter calibration procedure is listed in para 220-31.210 and 220-31.212. Only one daily calibration is needed when the pH measurements are to be made.

b. Measurement of Boiler Water pH.

NOTE

Do not filter any solution prior to pH measurement. Assure that the meter has been calibrated for the day.

(1) Rinse the thermometer, electrode and the plastic jar with distilled water and then with the sample. Pour sample into the jar until it is approximately half full.

(2) Place the thermometer and electrode into the jar and measure sample temperature.

(3) Slide mode switch to TEMP. Adjust TEMP readout using scroll ↑ and ↓ to the temperature of the sample. Press ENTER. Remove thermometer and rinse it with distilled water.

(4) Use the electrode as a stirring rod and stir the sample for 3 or 4 seconds. Then allow the electrode to rest against the side of the jar with the tip in the solution.

(5) Slide mode switch to pH. The SAMPLE LED will light.

(6) Wait until READY LED lights, then record the reading in the log. The READY light signifies that a stable reading has been obtained. Use Table 220-31-16 to correct the pH shown on the meter display. Look up the correction for the boiler water sample temperature and record the correction in the log. Add the correction to or subtract it from the displayed pH reading. Record the corrected value in the log.

(7) Remove the electrode and rinse it with distilled water. The SAMPLE LED will light indicating that the meter is now ready for the next sample.

(8) Store the electrode in potassium chloride solution between measurements. Replace the used potassium chloride solution weekly.

(9) Rinse the sample jar with distilled water.

NOTE

Boiler water treatment action is based on the corrected pH that is recorded in the log. It is not based on the reading showing on the meter display unless the sample temperature is 25°C (77°F).

5. Range of Error: the range of error of the test is ± 0.10 pH units.

220-31.215 EMERGENCY (CHEMICAL) BOILER WATER pH TEST.

This test may be used only if the meter test of paragraph 220-31.213 cannot be accomplished. Phenolphthalein indicator is added to a 200 ml sample which is then titrated with nitric acid. The buret reading is related to the pH of the boiler water. (This test is the first half of the boiler water phosphate test, refer to paragraph 220-26.28.)

1. Apparatus
   a. Nitric acid reagent bottle and buret assembly.
   b. Casserole.
   c. Stirring rod.
   d. Graduated cylinder, 100 ml.
2. Reagents
   a. Nitric acid reagent, 0.05 N (prepared from 50 ml of 1.0 N nitric acid stock solution, diluted to 1,000 ml with distilled water, refer to paragraph 220-24.47).
   b. Phenolphthalein indicator (2 level dippers of phenolphthalein dissolved in 25 ml of distilled water and 25 ml of isopropyl alcohol, refer to paragraph 220-24.49).
   c. Distilled water.
3. Interferences
   a. Absorption of carbon dioxide from the atmosphere lowers pH, refer to paragraph 220-31.203.
   b. Silica contamination causes a very high result. Excess morpholine in feedwater may cause a high boiler water result. If the approximate pH determined from the listing in Table 220-31-17 is unusually high, conductivity will confirm or deny results. See Table 220-31-3 and paragraph 220-23.21.6.
4. Procedure
   a. Rinse the casserole and stirring rod with distilled water.
   b. Rinse a 100 ml graduated cylinder with distilled water and then with some of the water to be tested.
   c. Measure exactly 200 ml of the sample into the casserole.
   d. Add 2 to 3 drops of phenolphthalein indicator to the sample water. The sample will turn pink if pH is greater than 8.2. (If it does not turn pink, assume that the sample is acidic.)
   e. Fill the nitric acid buret and drain to zero. Add nitric acid 1 drop at a time, while stirring, until the pink color disappears completely. Read the buret and record the result in the corrected pH column of the Boiler Water Chemistry Worksheet/Log. Use the following table to determine the approximate pH of the sample. Record the approximate pH in parentheses next to the buret reading in the same column.
   f. The approximate pH of the sample is given in Table 220-31-17.
5. Range of Error: the range of error of the test is ±0.2 pH unit below pH 10.4 and ±0.1 pH unit above pH 10.4.

220-31.216 EMERGENCY BOILER WATER PHOSPHATE TEST.

This test may be used only when acceptable phenolphthalein or methyl purple indicator is not available. This test is performed by measuring the pH of the sample while titrating the sample with nitric acid reagent first to a pH of 8.2. The buret is then rezeroed, and the sample titrated to a pH of 5.4. The buret reading at pH 5.4, multiplied by 25, yields the phosphate value in ppm.

1. Apparatus

a. Meter, digital pH, Model 601N, requires 110-115 volt power supply, or Model SA 720, requires 110 or 220 volt power supply or six 1.5 V AA non-rechargeable alkaline batteries.

b. pH electrode, combination gel-filled, connected to the pH meter.

c. Thermometer, metal, dial type 0°C to 100°C (32°F to 212°F).

d. Jar, plastic, wide-mouth (marked and used for sample only).

e. Nitric acid reagent bottle and buret assembly.

f. Graduated cylinder, 100 ml.

g. Adaptor, U.S. Standard to BNC connector for Model SA 720 only. Its function is to connect the electrode probe to the meter. The small female connector on the adaptor is not used.

2. Reagents

a. Nitric acid reagent, 0.05 N (prepared from 50 ml of 1.0 N nitric acid stock solution diluted to 1,000 ml with distilled water, refer to paragraph 220-24.47).

b. A 3-Molar potassium chloride solution, 1/2 pound of potassium chloride per quart of distilled water. Refer to paragraph 220-31.206.

c. Dilute caustic soda, about 3 flakes of caustic soda dissolved in 50 ml of distilled water. Refer to paragraph 220-24.56. The dilute caustic soda, solution is needed if pH is less than 8.2.

d. Distilled water.

3. Interferences

a. Oil and suspended matter may coat the electrode making it inoperable.

4. Procedure

a. Daily Standardization. The meter standardization procedure for the Model 601N is listed in paragraphs 220-31.209 and 220-31.211. The meter standardization procedure for the Model SA 720 is listed in paragraphs 220-31.210 and 220-31.212. Only one daily standardization is needed when pH measurements are to be made.

b. Measurement of boiler water phosphate using the pH meter.

NOTE

Model 601N

Do not filter any solution prior to pH measurement. Assure that the function switch is in the STDBY position and that the meter has been warmed up for at least 30 minutes. Assure that the meter has been standardized for the day. The temperature of the sample shall be adjusted to 25°C ±32°C (77°F ±5°F). Never remove the electrode from the solution unless the function switch is in the STDBY position.

NOTE

Model SA 720

Daily standardization is required when pH measurements are to be made. Restandardize any time power to the meter is interrupted. Do not filter any solution prior to pH measurement. The temperature of both buffer solutions shall be adjusted to 25°C ±3°C (77°F ±5°F). Warm up time for the Model SA 720 is not required.

(1) Rinse the thermometer, electrode, and the plastic jar with distilled water.

(2) Rinse the 100 ml graduated cylinder with distilled water and then with some of the sample.

(3) Measure exactly 200 ml of the sample into the plastic jar.

(4) Measure the temperature of the boiler water and set the TEMP control of the Model 601N to the sample temperature. For the Model SA 720, slide the mode switch to TEMP. Adjust TEMP readout using scroll ↑ and ↓ to the temperature of the sample. Remove the thermometer and rinse it with distilled water.

(5) Use the electrode to stir the sample for 3 or 4 seconds. Then allow the electrode to rest against the side of the jar with the tip in the solution.

(6) Turn the function switch to the pH position and observe the reading on the Model 601N. For the Model SA 720, slide the mode switch to pH. The SAMPLE LED will light. Observe the reading after the READY LED lights. Leave the electrode in the solution. It will be used as a stirring rod. Leave the function switch in the pH position until completion of the test.

NOTE

If the initial pH of the sample is below 8.2, insert CS in the ml phenolphthalein column of the boiler water log. Add diluted caustic soda solution (paragraph 220-24.56) a drop at a time to the sample, while stirring, until the pH is greater than 8.2; then continue with the procedure. Note in the remarks section of the log that diluted caustic soda solution was added.

(7) Remove the nitric acid assembly from the test cabinet, position the buret tip over the jar, and zero the buret.

(8) Add nitric acid slowly, one drop at a time, while stirring and observing the meter display until the pH is between 8.1 and 8.3. Discontinue stirring in order to obtain a stable meter reading. Record the buret reading in the ml phenolphthalein column so long as diluted caustic soda solution was not added to the sample. If diluted caustic soda solution was added, only CS is inserted. Rezero the buret.

(9) Continue adding nitric acid slowly, while stirring and observing the meter display until the pH is between 5.3 and 5.5. Discontinue stirring in order to obtain a stable meter reading. Record this buret reading in the ml methyl purple column. Multiply this buret reading by 25 and record the result in ppm phosphate. For example, for a buret reading of 3.8 ml at an approximate pH of 5.4:

3.8 ml x 25 = 95.0 ppm phosphate

(10) Return the function switch to the STDBY position on the Model 601N. The Model SA 720 will remain in the SAMPLE position.

(11) Remove the electrode and rinse it with distilled water. Store it in potassium chloride solution between measurements and replace the used potassium chloride solution weekly.

5. Range of Error: the range of error of the test is 10 ppm (10 mg/l) phosphate.

Table 220-31-17 APPROXIMATE pH --TITRATION BASIS

ml of Nitric Acid	Approximate pH	ml of Nitric Acid	Approximate pH
0.0	8.20 or less	2.6	10.81
0.1	8.30 to 9.7	2.7	10.83
0.2	9.70	2.8	10.85
0.3	9.88	2.9	10.86
0.4	10.00	3.0	10.88
0.5	10.10	3.1	10.89

Table 220-31-17 APPROXIMATE pH --TITRATION BASIS - Continued

ml of Nitric Acid	Approximate pH	ml of Nitric Acid	Approximate pH
0.6	10.18	3.2	10.90
0.7	10.24	3.3	10.92
0.8	10.30	3.4	10.93
0.9	10.35	3.5	10.94
1.0	10.40	3.6	10.95
1.1	10.44	3.7	10.97
1.2	10.48	3.8	10.98
1.3	10.51	3.9	10.99
1.4	10.54	4.0	11.00
1.5	10.57	5.0	11.10
1.6	10.60	6.4	11.20
1.7	10.63	8.0	11.30
1.8	10.65	10.0	11.40
1.9	10.68	12.8	11.50
2.0	10.70	16.0	11.60
2.1	10.72	20.0	11.70
2.2	10.74	25.6	11.80
2.3	10.76	32.0	11.90
2.4	10.78	40.0	12.00
2.5	10.80	--	--

220-31.217 EMERGENCY BOILER WATER CONDUCTIVITY AND CHLORIDE TESTS.

There are no test procedures that substitute for the conductivity and chloride tests; however, either of these values can be approximated from Table 220-31-3 if the other boiler water parameters are known.

220-31.218 TROUBLES WITH BOILER CHEMICAL INJECTION.

Failure of boiler water pH or phosphate to rise after chemical injection indicates a problem. Either the treatment chemicals did not get into the boiler, or the treatment chemicals injected were not the right material. Improper chemical injection procedure, improper valve lineup, plugged treatment lines or leaking valves could cause chemicals to be injected to the bilge or to another boiler in the space, or not at all. This can be checked by visual inspection of the tank drain during injection, by double checking the valve lineup, and by sampling the other boiler for unexpected rise in pH or phosphate. Treatment chemicals themselves can be quickly checked by dissolving a teaspoon of each chemical in about 100 ml of distilled water, then measuring its pH. The disodium phosphate solution should have a pH of about 9 and the trisodium phosphate solution should have a pH of about 12. Another method for checking treatment chemicals follows:

1. Observe all normal precautions for a boiler water pH measurement.
2. Measure 250 ml of distillate into a clean plastic jar.
3. Add either trisodium phosphate or disodium phosphate, a few crystals at a time, while stirring the solution with the pH electrode, until the meter reads between pH 9 and pH 11. Let the electrode rest against the side of the jar until a stable reading is obtained. Note the reading.
4. Measure the phosphate concentration in accordance with the normal boiler water phosphate test.
5. Plot the pH reading versus the phosphate concentration on Figure 220-31-11.

6. If the sample is trisodium phosphate, the pH and phosphate values should fall near the trisodium phosphate curve.

7. If the sample is disodium phosphate, the pH and phosphate values should fall near the disodium phosphate curve.

NOTE

Figure 220-31-11 shows that when disodium phosphate is added to distilled water, pH increases and phosphate concentration increases. Figure 220-31-1 and Figure 220-31-3 along with their associated texts describe no pH effect caused by addition of disodium phosphate to boiler water. All figures are correct. When disodium phosphate is added to boiler water, which is already alkaline, the increase in hydroxide ion concentration has little or no detectable pH effect. However, when disodium phosphate is added to neutral water, a pH increase is measurable.

220-31.219 COORDINATED PHOSPHATE RECORD MAINTENANCE

220-31.220

The Feedwater Chemistry Worksheet/Log and the Boiler Water Chemistry Worksheet/Log replace the logs for chelant treatment. The Cover Sheet and Monthly Boiler Data, the Boiler Water/Feedwater Test and Treatment Chemical Inventory Log, the Reserve/Makeup Feedwater Test logs, and the Fuel and Water Report are used for both treatments. The Cover Sheet and Monthly Boiler Data, Boiler Water/Feedwater Test and Treatment Chemical Inventory Log, Fuel and Water Report, and Reserve/Makeup Feedwater Test logs are maintained in accordance with Section 27.

220-31.221 FEEDWATER CHEMISTRY WORKSHEET/LOG.

The Daily Feedwater Chemistry Log, NAVSEA 9255/4 (6/94), is maintained in accordance with paragraph 220-27.11 except that the deaerated feedwater section replaces the feedwater treatment section. This section shall be maintained for deaerated and morpholine treated feedwater as follows:

1. Enter the time of completion of sampling.
2. Enter the appropriate code as given on front of log sheet.
3. Enter the dissolved oxygen content test result.
4. If feedwater is morpholine treated, enter:
   a. pH result.
   b. Morpholine rotameter setting at time of sampling.
   c. Morpholine tank water level.

A typical log is shown in Figure 220-31-12.

220-31.222 BOILER WATER CHEMISTRY WORKSHEET/LOG.

The daily log (Figure 220-31-12, sheets 3, 4, 5, and 6) consists of the following sections:

1. Chemical Test Results.
2. Chemical Treatment.
3. Blowdown.
4. pH Meter Standardization.
5. Steaming Hour Data.
6. Remarks.
7. % Boiler Load.

220-31.223

Initiate the daily log for each boiler by inserting the boiler number, the ship name and hull number, and the date.

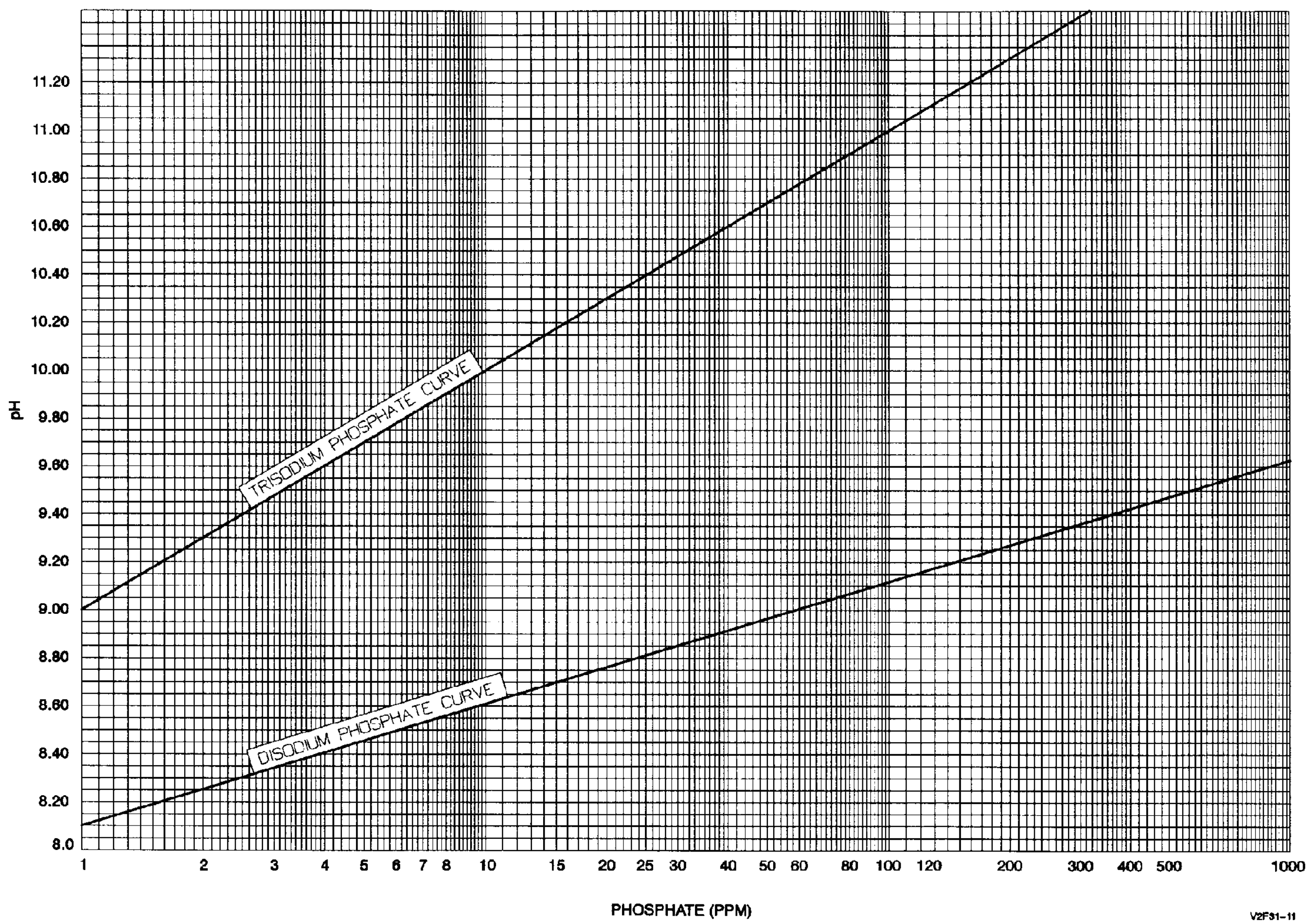


Figure 220-31-11 pH and Phosphate Relationships for treatment Chemicals

220-31.224 Chemical Test Results Section.

This section (Figure 220-31-12, sheets 3 and 5) shall be maintained as follows:

1. Enter the time on a 24 hour clock basis for the following:
   a. Completion of boiler water sampling.
   b. Commencement of layup conditions.
   c. Securing of layup conditions.
   d. Light-off.
   e. On-line.
   f. Securing.
   g. Completion of dumping.
   h. Completion of freshly filling.
   i. Completion of chemical additions.
   j. Completion of blowdowns.
   k. Completion of any tests including hydrostatic tests.
   l. Other items of interest.

2. Enter the appropriate code as given on the back of the log. If a specific code is not provided, enter OTH and write out what took place in the remarks section. If the boiler is not steaming, a 0001 entry should be made each day with the appropriate layup code. One sheet may be used to cover a number of days in a single month if a boiler is in layup, but a date should be added to the time (day of month followed by time). For example, 050001 STM, refers to the fifth day of the month at 0001 hrs.

3. For each boiler water sample, record:
   a. The sample temperature, the pH meter reading, the pH correction for that temperature, and the corrected pH.
   b. The conductivity.
   c. The ml of nitric acid needed to change phenolphthalein from pink to colorless, approximate pH from Table 220-31-17 the ml of nitric acid needed to change methyl purple from green to purple, and the calculated phosphate test result.
   d. The ml of mercuric nitrate used and the calculated chloride test result.
   e. The percent boiler load by the following formula:
   The percent boiler load for M type boilers is calculated for boiler water treatment considerations by using

$$\text{\% BOILER LOAD} = 100 \times \frac{BFR \times BIS}{FPFR}$$

where: BFR = Burner firing rate in lbs/hr obtained from sprayer plate capacity curve knowing the fuel oil header pressure

BIS = Number of burners in service

FPFR = Boiler full power firing rate in lbs/hr or burner full power firing rate in lbs/hr multiplied by the maximum number of burners per boiler

   the above formula for the saturated side only. Each ship should prepare a table for percent boiler load for various fuel oil header pressures and burner alignments. Percent boiler load shall be rounded to the nearest whole number.

4. The Oil King enters his initials and the reviewing EOOW/EDO enters his initials upon completion of the tests.

220-31.225 Chemical Treatment Section.

This section (Figure 220-31-12, sheet 3 and 5) shall be maintained as follows:

1. Enter the amount of trisodium phosphate required to raise pH to the upper limit.
2. Enter the phosphate correction that will be caused by addition of trisodium phosphate.
3. Enter the phosphate reading obtained from original sample results.
4. Add the correction to the original phosphate reading and enter the corrected phosphate.
5. Enter the amount of disodium phosphate required.
6. Enter the time of completion of the 10-minute flush when injecting boiler water treatment chemicals.
7. If necessary, enter the amount of caustic soda required.
8. Enter the total amounts of all chemicals used for the day on the last log for the day.

220-31.226 Blowdown Sections.

The blowdown section (Figure 220-31-12, sheet 3 and 5 shall be maintained as follows:

1. Enter the time of completion of a surface, bottom, or header blowdown operation. If a blowdown spans two dates, record time on the date of completion.
2. Enter the appropriate code, as given on the back of the log, for the type of blowdown.
3. For surface blowdown, enter the conductivity before blowdown, the conductivity after blowdown, and the calculated percent blowdown.
4. Enter the total percent of surface blowdown on the last log for the day.

220-31.227 pH Meter Standardization Section.

For this section (Figure 220-31-12, sheets 3 and 5) enter the time of completion of the standardization and the percent slope reading from the meter. The person performing the standardization enters his initials. Enter the standardization data on the logs for all steaming boilers. Figure 220-31-12. Water Treatment Log (Sheet 2 of 6) Water Treatment Log (Sheet 3 of 6)

220-31.228 Steaming Hours Data Section.

This section (Figure 220-31-12, sheets 4 and 6) shall be completed by entering into the prior hours steamed this month blocks the steaming hours and steaming hours under moderate and serious contamination from the hours steamed this month blocks of the previous day's log. For the first day of the month, enter zeros into the prior hours steamed this month blocks. Enter into the hours steamed today blocks the current day's steaming hours and steaming hours under moderate and serious contamination. Steaming hours are recorded to the nearest 0.1 hours from light-off to securing. Steaming hours under contamination for boiler water start from the sample time when the contamination was detected to the sample time when the boiler water conditions are back within limits or the boiler is secured. Steaming hours under contamination for feedwater dissolved oxygen are not included in the steaming hours contamination section. Add the prior hours steamed this month to the hours steamed today to obtain the hours steamed this month. Enter the hours since the last waterside inspection, fireside inspection and bottom blowdown. If more than one log is used for the boiler in any one day, then enter the data on the last log for the day.

FEEDWATER CHEMISTRY WORKSHEET/LOG

SYSTEM ONE SHIP USS CARRIER (CV-50) DATE 21JUN94 PAGE 161

CHEMICAL TESTS AND SALINITY/CONDUCTIVITY INDICATOR COMPARISON (REQUIRED DAILY) NOTE: µmho/145=epm

TIME	INDICATOR LOCATION	CHLORIDE ml MERCURIC NITRATEx0.1= epm CHLORIDE		INDICATOR READING		COM-PARISON	HARDNESS ml EDTAx0.2= epm HARDNESS		OIL KING INITIAL
		ml	epm	µmho/cm	epm	SAT/UNSAT	ml	epm	
0005	MUF	0.3	.03	4.0	.02	SAT			[illegible]
0015	MN COND	0.1	.01	3.3	.02	SAT			[illegible]
0018	IA SSTG	0.1	.01	2.8	.02	SAT			[illegible]
0020	IB SSTG	0.1	.01	2.6	.02	SAT			[illegible]
0025	DFT	0.1	.01	3.8	.02	SAT			[illegible]
0030	AGEC	0.2	.02	3.4	.02	SAT			[illegible]
0035	FWDCT	0.2	.02	6.5	.05	UNSAT	0.1	.02	[illegible]
0350	FWDCT	0.1	.01	3.8	.02	SAT			[illegible]

DEAERATED FEED WATER

TIME	CODE	DISSOLVED OXYGEN LIMIT: 15 ppb	MORPHOLINE pH RANGE: 8.6–9.0	MORPHOLINE ROTAMETER SETTING	MORPHOLINE TANK LEVEL (gallons)
0915	RTE	10			
0945	RTE		8.6-9.0	5	15

FEEDWATER TESTS

TIME	LOCATION	INDICATOR READING µmho/cm / epm	CHLORIDE ml MERCURIC NITRATEx0.1= epm CHLORIDE		HARDNESS ml EDTAx0.2= epm HARDNESS		OIL KING INITIAL
			ml	epm	ml	epm	
0300	FWDCT		0.2	.02			[illegible]

NAVSEA 9255/4 (6-94)(FRONT) NSN 0116-LF-018-2200

Figure 220-31-12 Water Treatment Log Sheet (1 of 6)

FEEDWATER CHEMISTRY WORKSHEET/LOG

PAGE 162

TIME	REMARKS:
0035	Comparison test UNSAT. Conductivity indicator reading is greater than chemical
	chloride test result by more than 0.02 epm. Water tested for hardness. Hardness
	less than 0.02 epm. Morpholine level within limits. Per NSTM 220 para
	22.6.3 water is SAT for use and conductivity indicator will be checked
	for malfunction. Test water every 4 hours.
0330	Conductivity cell cleared.
0350	Comparison test SAT. Stop 4-hour samples.

LEGEND/TEST CODE	
DISSOLVED OXYGEN TESTING	MORPHOLINE TREATED SYSTEM
PFB PRIOR TO FEEDING THE BOILER AOL WITHIN 2-3 HOURS AFTER BOILER ON LINE RTE WITHIN 24 HOURS	AOL 60 TO 90 MINUTES AFTER ON LINE RTE CARRIERS EVERY 4 HOURS OTHERS EVERY 12 HOURS

REQUIREMENTS/LIMITS (MAXIMUM)		CHLORIDE epm SALINITY INDICATOR	CHLORIDE epm CHEMICAL TEST	CONDUCTIVITY µmho/cm	HARDNESS epm
DISTILLATE		0.065	0.07	10.0	–
MAKEUP	DEMINERALIZED	–	–	1.0	–
	NONDEMINERALIZED	0.10	0.10	15.0	0.10
CONDENSATE, DRAINS & DFT	MORPHOLINE TREATED	0.04	0.02	6.0	0.02
	WITHOUT MORPHOLINE	0.02	0.02	3.0	0.02
DISTILLER AIR EJECTOR DRAINS		0.065	0.02	10.0	–

LCPO INIT.	LCPO DATE	MPA INIT.	MPA DATE	REVIEWED: (ENGINEER OFFICER)	DATE
CJM	22JUN94	BSW	22Jun94	Cdr C. S. Mahoney	22 June 1994

NAVSEA 9255/4 (6-94)(BACK) NSN 0116-LF-018-2200

Figure 220-31-12 Water Treatment Log Sheet (2 of 6)

BOILER WATER CHEMISTRY WORKSHEET/LOG

BOILER NO. 1A SHIP USS REPLENISHMENT (AOE-20) DATE 1 JUNE 1994 PAGE 3

TIME	CODE	pH RANGE: TYPE A: 10.20–10.60 TYPE B: 9.80–10.20				CONDUCTIVITY LIMIT: TYPE A: 600 TYPE B: 400 µmho/cm	PHOSPHATE RANGE: TYPE A: 50–120 ppm TYPE B: 25–60 ppm				CHLORIDE LIMIT: 1.00 epm		BOILER LOAD PERCENT %	OIL KING INITIAL	EOOW/ EDO INITIAL
		TEMP (°C)	pH METER READING	CORREC-TION	CORRECTED pH	CONDUCTIVITY µmho/cm	ml PHEN-OLPH-THALEIN	APPROX-IMATE pH	ml METHYL PURPLE	ml x 25 = ppm PHOSPHATE	ml MERC. NITRATE	ml x 0.4 = epm CHLORIDE			
0010	PTL	25	9.50	0.00	9.50	90	0.1	8.3–9.7	0.6	15	0.7	0.28	—	[illegible]	[illegible]
0052	LOF														
0230	ONL														
0249	AOL 1	26	9.57	+0.02	9.59	90	0.1	8.3–9.7	0.7	17.5	0.7	0.28	6	[illegible]	[illegible]
0354	AOL 2	26	9.60	+0.02	9.62	95	0.1	9.3–9.7	0.8	20	0.7	0.28	12	[illegible]	[illegible]
0459	AOL 3	26	9.60	+0.02	9.62	100	0.1	9.3–9.7	0.8	20	0.8	0.32	15	[illegible]	[illegible]
0520	ADD														
0630	ACA	25	10.20	0.00	10.20	200	0.6	10.2	2.0	50	0.8	0.32	20	[illegible]	[illegible]
1350	RTE	26	10.16	+0.02	10.18	200	0.6	10.2	1.8	45	1.0	0.40	40	[illegible]	[illegible]
1435	OTH	24	9.7	-0.02	9.68	260	0.1	9.3–9.7	0.8	20	3.5	1.40	50	[illegible]	[illegible]
1450	ADD														
1600	ACA/PTB	26	10.14	+0.02	10.16	346	0.6	10.2	1.8	45	3.6	1.44	40	CP	RBP
1630	S														
1705	ADD/PTB	26	10.09	+0.02	10.11	313	0.5	10.1	1.6	40	3.3	1.32	35	CP	RBP

CHEMICAL TREATMENT						
TRISODIUM PHOSPHATE (ounces)	TSP CORRECTION FOR PHOSPHATE	CURRENT PHOSPHATE LEVEL	CORRECTED PHOSPHATE	DISODIUM PHOSPHATE (ounces)	CAUSTIC SODA (ounces)	TIME INJECTED
10.5	10	20	30	7.5	—	0520
10.5	10	20	30	7.5	—	1450

BLOWDOWN				
TIME	TYPE	CONDUCTIVITY BEFORE	CONDUCTIVITY AFTER	% SURFACE BLOW-DOWN
1630	S	346	313	9.5

pH METER STANDARDIZATION		
TIME	% SLOPE (92% MIN)	INITIAL
0001	100	[illegible]

TOTAL TSP INJECTED	TOTAL DSP INJECTED	TOTAL CAUSTIC SODA INJECTED	TOTAL PERCENT SURFACE BLOWDOWN

NAVSEA 9255/8 (6–94)(FRONT)

Figure 220-31-12 Water Treatment Log Sheet (3 of 6)

BOILER WATER CHEMISTRY WORKSHEET/LOG

PAGE 4

TIME	REMARKS:
0010	PTL- Meets LOF requirements.
0249	AOL1- pH & phosphates low out of limits, SAT for 1ST AOL.
0354	AOL2- pH & phosphates low out of limits, SAT for 2nd AOL.
0459	AOL3- pH & phosphates low out of limits, Recommend treat boiler to upper limits.
1435	OTH- Auxiliary gland exhaust condenser is high out of limits, EOOW ordered
	boiler be tested. Boiler test results indicated moderate contamination (seawater
	contamination). Phosphates & pH low out of limits, chloride high out of limits, gland
	exhaust condenser cut out of system. Recommend treat boiler to upper
	limits and conduct surface blowdown to return chloride to limits.
1600	ACA/PTB- Chloride high out of limits. Recommend surface blowdown.
1705	ABD/PTB- Chloride still high out of limits. Recommend surface blowdown.

LEGEND/TEST CODE

- PTL WITHIN 60 MIN. PRIOR TO LIGHTOFF
- AOL1 WITHIN 30 MIN. AFTER ON LINE
- AOL2 WITHIN 60 TO 75 MIN. AFTER AOL1
- AOL3 WITHIN 60 TO 75 MIN. AFTER AOL2
- RTE WITHIN 8 HOURS
- ADD CHEMICAL ADDITION
- ACA 60 TO 90 MIN. AFTER CHEMICAL ADDITION
- PTB WITHIN 60 MIN. PRIOR TO BLOWDOWN
- ABD 30 TO 45 MIN. AFTER BLOWDOWN
- PTS WITHIN 90 MIN. PRIOR TO SECURING
- FFT FRESHLY FILLED AND TREATED
- LOF LIGHTOFF
- ONL ON LINE
- SEC SECURED
- D DUMPED
- OTH OTHER

BOILER LAYUP

DRY LAYUP
- DES DESICCANT
- HTD HEATED AIR

WET LAYUP
- STM STEAM (SHIP)
- STS STEAM (SHORE)
- NIT NITROGEN
- DFT HOT DFW FILL
- HYD HYDRAZINE
- SN SODIUM NITRITE

BLOWDOWNS
- S SURFACE
- B BOTTOM

	STEAMING HOURS	STEAMING HOURS UNDER CONTAMINATION	
		MODERATE	SERIOUS
PRIOR HOURS STEAMED THIS MONTH			
HOURS STEAMED TODAY			
HOURS STEAMED THIS MONTH			
HOURS SINCE LAST WATERSIDE INSPECTION			
HOURS SINCE LAST FIRESIDE INSPECTION			
HOURS SINCE LAST BOTTOM BLOWDOWN			

LCPO INITIAL	LCPO DATE	MPA INITIAL	MPA DATE	REVIEWED: (ENGINEER OFFICER)	DATE
[illegible]	2 Jun 94	DAE	2 Jun 94	LC M. J. Haggerty	2 June 1994

NAVSEA 9255/8 (6-94)(BACK)

Figure 220-31-12 Water Treatment Log Sheet (4 of 6)

BOILER WATER CHEMISTRY WORKSHEET/LOG

PAGE 6

TIME	REMARKS:
1817	ABD/PTB-Chloride still high out of limits. Recommend surface blowdown.
1925	ABD-Chloride high out of limits. Phosphate nearing lower limits. Recommend treat
	boiler to upper limits and continue surface blowdowns.
2115	ACA/PTB-pH & Phosphates at upper limit. Chloride still high. Recommend surface
	blowdown.
2225	ABD/OTH-All boiler Parameters within limits. Cause of seawater contamination was
	leaking bell at tube end in the auxiliary gland exhaust condenser. Condenser
	has been repaired and returned to service.

LEGEND/TEST CODE

PTL	WITHIN 60 MIN. PRIOR TO LIGHTOFF
AOL1	WITHIN 30 MIN. AFTER ON LINE
AOL2	WITHIN 60 TO 75 MIN. AFTER AOL1
AOL3	WITHIN 60 TO 75 MIN. AFTER AOL2
RTE	WITHIN 8 HOURS
ADD	CHEMICAL ADDITION
ACA	60 TO 90 MIN. AFTER CHEMICAL ADDITION
PTB	WITHIN 60 MIN. PRIOR TO BLOWDOWN
ABD	30 TO 45 MIN. AFTER BLOWDOWN
PTS	WITHIN 90 MIN. PRIOR TO SECURING
FFT	FRESHLY FILLED AND TREATED
LOF	LIGHTOFF
ONL	ON LINE
SEC	SECURED
D	DUMPED
OTH	OTHER

BOILER LAYUP

DRY LAYUP

DES	DESICCANT
HTD	HEATED AIR

WET LAYUP

STM	STEAM (SHIP)
STS	STEAM (SHORE)
NIT	NITROGEN
DFT	HOT DFW FILL
HYD	HYDRAZINE
SN	SODIUM NITRITE

BLOWDOWNS

S	SURFACE
B	BOTTOM

	STEAMING HOURS	STEAMING HOURS UNDER CONTAMINATION	
		MODERATE	SERIOUS
PRIOR HOURS STEAMED THIS MONTH	Ø	Ø	Ø
HOURS STEAMED TODAY	23.1	7.8	Ø
HOURS STEAMED THIS MONTH	23.1	7.8	Ø
HOURS SINCE LAST WATERSIDE INSPECTION	926.6		
HOURS SINCE LAST FIRESIDE INSPECTION	360.7		
HOURS SINCE LAST BOTTOM BLOWDOWN	23.1		

LCPO INITIAL	LCPO DATE	MPA INITIAL	MPA DATE	REVIEWED: (ENGINEER OFFICER)	DATE
JJA	2 Jun 94	BKd	2 Jun 94	LT M. J. Haggerty	2 June 1994

NAVSEA 9255/8 (6-94)(BACK)

Figure 220-31-12 Water Treatment Log Sheet (5 of 6)

BOILER WATER CHEMISTRY WORKSHEET/LOG

BOILER NO. 1A SHIP USS REPLENISHMENT (AOE-20) DATE 1 JUNE 1994 (CONT'D) PAGE 5

TIME	CODE	pH RANGE: TYPE A: 10.20–10.60 TYPE B: 9.80–10.20				CONDUCTIVITY LIMIT: TYPE A: 600 TYPE B: 400 µmho/cm	PHOSPHATE RANGE: TYPE A: 50–120 ppm TYPE B: 25–60 ppm				CHLORIDE LIMIT: 1.00 epm		BOILER LOAD PERCENT %	OIL KING INITIAL	EOOW/EDO INITIAL
		TEMP (°C)	pH METER READING	CORREC-TION	CORRECTED pH	CONDUCTIVITY µmho/cm	ml PHEN-OLPH-THALEIN	APPROX-IMATE pH	ml METHYL PURPLE	mlx25= ppm PHOSPHATE	ml MERC. NITRATE	mlx0.4= epm CHLORIDE			
1745	S														
1817	ABD/PTB	25	10.04	0.00	10.04	280	0.4	10.00	1.4	35	3.0	1.20	35	[illegible]	[illegible]
1850	S														
1925	ABD	25	9.99	0.00	9.99	240	0.4	10.00	1.2	30	2.6	1.04	35	[illegible]	[illegible]
2000	ADD														
2115	ACN/PTB	26	10.17	+0.02	10.19	300	0.6	10.20	1.9	47.5	2.6	1.04	40	CP	RBP
2145	S														
2225	ABN/OTA	25	10.12	0.00	10.12	260	0.5	10.10	1.7	42.5	2.4	0.92	40	CP	RBP

CHEMICAL TREATMENT						
TRISODIUM PHOSPHATE (ounces)	TSP CORRECTION FOR PHOSPHATE	CURRENT PHOSPHATE LEVEL	CORRECTED PHOSPHATE	DISODIUM PHOSPHATE (ounces)	CAUSTIC SODA (ounces)	TIME INJECTED
5.5	2.5	30	32.5	5.5	—	2000

BLOWDOWN				
TIME	TYPE	CONDUCTIVITY BEFORE	CONDUCTIVITY AFTER	% SURFACE BLOW-DOWN
1745	S	313	280	10.5
1850	S	280	243	13.2
2145	S	300	260	13.3

pH METER STANDARDIZATION		
TIME	% SLOPE (92% MIN)	INITIAL

TOTAL TSP INJECTED	TOTAL DSP INJECTED	TOTAL CAUSTIC SODA INJECTED	TOTAL PERCENT SURFACE BLOWDOWN
26.5	20.5	0.0	46.5

NAVSEA 9255/8 (6–94)(FRONT)

Figure 220-31-12 Water Treatment Log Sheet (6 of 6)

220-31.229 Remarks Section.

The remarks section (Figure 220-31-12, sheets 4 and 6) shall describe significant events of the day related to that boiler. Additional pages for remarks shall be inserted as necessary. All remarks are accompanied by the time as appropriate. If a doubt exists as to whether or not an entry should be made in the remarks section, enter it. The following types of events shall be recorded:

1. The setting of boiler safety valves.
2. Hydrostatic tests, including purpose and pressure, and the signature of the witnessing individual.
3. A brief summary of boiler repairs accomplished.
4. Boiler inspection.
5. Explanation of each test result which is out of limits.
6. The reason for using an emergency pH or phosphate test and action taken to correct the situation causing use of the emergency tests.

7. Description of unusual conditions.

8. The results of tests of boiler water/feedwater chemicals against standards, except the quarterly tests, are entered on the log for the 1 or 1A boiler. (The quarterly standard test results are entered on the monthly boiler data log for the number 1 plant.)

9. Theoretical conductivity for a steaming boiler once daily.

220-31.230

The Boiler Water Chemistry Worksheet/Log need not be prepared on a daily basis when the boiler is idle. When the boiler is idle, enter the inclusive dates on the front of one log and enter the type of layup applied in the code column, and describe significant events occurring during the idle period. For every day that there is a log the LCPO shall review and initial the log.

220-31.231 REPORTS TO HIGHER AUTHORITIES

220-31.232

When the cognizant activity (ship NAVSHIPYARD, SUPSHIP) is requesting technical assistance or is reporting in accordance with paragraph 220-23.26, the following information shall be detailed in a report to the Type Commander with information copy to the ISIC, NAVSEA and NSWCCD-SSES.

Boiler Water	Feedwater
1. Date, time, and code (DTC).	1. Date, time, and code (DTC).
2. Corrected pH (pH).	2. Dissolved O_2 (DO).
3. Conductivity (COND).	3. epm chloride (chemical test) (CL).
4. ml phenolphthalein (ML).	4. Salinity/conductivity reading (SI/COND).
5. ppm phosphate (PHOS).	5. pH.
6. epm chloride (CL).	6. Morpholine treatment rate (MOR).
7. Percent boiler load (LD).	
8. Chemical additions (CA).	
9. Blowdowns (BD).	

Messages shall be formatted with the above information as follows:

For boiler water, read in nine columns:

DTC	pH	COND	ML	PHOS	CL	LD	CA	BD

For feedwater/condensate, read in six columns:

DTC	DO	CL	SI/COND	pH	MOR

The report shall include data for at least two samples taken prior to the contamination incident.

220-31.233 SUPPLY INFORMATION

220-31.234

Supply information in contained in Section 28. Supply procedures, sampling equipment, conductivity test equipment, dissolved oxygen test kit, EDTA hardware test equipment and silica test kit are all applicable to coordinated phosphate treatment. Additional guidance is included here.

220-31.235 pH TEST EQUIPMENT.

The following pH test equipment provides all the items required for the pH tests of boiler water.

Quantity	Item	NSN
1	Meter, digital pH	1H 6625-01-070-2446
2	Electrode, gel-filled, combination pH	9L 6630-01-063-9985
3	Jars, wide-mouth plastic with screw cap	9L 6640-01-068-5095
1	Thermometer, metal, dial type (0°C to 100°C) (32°F to 212°F)	9G 6685-00-663-8093
1	Buffer capsules pH 7.00 ± 0.05 at 25°C (77°F) (contains 50 capsules)	9G 6810-01-239-7562
1	Buffer capsules pH 10.00 ± 0.05 at 25°C (77°F) (contains 50 capsules)	9G 6810-01-239-7563
1	Bottle, drop dispenser, 60 ml (for electrode storage)	9L 6640-00-720-2752
2	Potassium chloride, ACS crystals (1/4 pound)	9L 6810-00-136-1004
1	Bottle, polyethylene, screw cap, 1 qt	9G 8125-00-819-6085
1	Adaptor (to connect electrode to Model SA 720 meter)	1H 0099-LL-H26-4985

220-31.236 STANDARDS FOR VERIFICATION TESTING.

Stock chemicals, reagent chemicals, and conductivity equipment can deteriorate. Standards are available to check the accuracy of boiler water and feedwater test chemicals and equipment. The standards available for verification testing are as follows:

Item	NSN
Standard conductivity solution (1,400 µmho/cm)	9G 6810-00-945-7682
Standard chloride solution (2.0 epm)	9G 6810-01-129-3762
Standard hardness solution (0.2 epm)	9G 6810-01-125-5234
Standard pH buffer capsules [7.00 ± 0.05 at 25°C (77F°)]	9G 6810-01-239-7562
Standard pH buffer capsules [10.00 ± 0.05 at 25°C (77°F)]	9G 6810-01-239-7563
Standard methyl purple alkalinity (6.0 epm)	9G 6810-01-259-8231

220-31.237

All of the foregoing standards, except the pH standards, are supplied as solutions in small plastic bottles. The pH standards are supplied in vials containing 10 capsules. The contents of one capsule are dissolved in 100 ml of distilled water and the solution is sufficient for one test only. All standard solutions must be discarded after one use. Quarterly verification testing is to be performed when a new reagent solution is prepared, and whenever the validity of a test result is in doubt. The pH meter is standardized daily when in use.

220-31.238 TREATMENT CHEMICALS.

The treatment chemicals are as follows:

Item	NSN
Trisodium phosphate, dodecahydrate (25 lb drum) (O-S-642, Type II)	9G 6810-01-082-5415
Caustic soda (lye, sodium hydroxide, 500 g bottle)	9Q 6810-00-270-8177
Morpholine, 40 percent (5 gal can)	9G 6810-00-419-4298
Disodium phosphate (sodium phosphate dibasic, 25 lb drum) (O-S-639)	9G 6810-00-584-4298
Ion exchange resin	1H 6810-01-029-4217

220-31.239 SAFETY EQUIPMENT.

Protective equipment is required when handling corrosive materials such as acids or alkalies. Useful equipment is as follows:

Item	NSN
Apron, synthetic rubber	9Q 8415-00-634-5023
Face shield, industrial	9Q 4240-00-542-2048
Gloves, rubber	9D 8415-00-266-8677
Gloves, plastic	9D 8415-00-682-6786
Goggles, chemical safety	9G 4240-01-364-2169

220-31.240

Rubber gloves give long term protection; however, rubber gloves may not give positive control of an operation as do plastic gloves. Plastic gloves give better hand control but can be used only once. The average size for rubber gloves is 10 and for plastic gloves, medium.

220-31.241 MISCELLANEOUS MATERIAL.

Miscellaneous material that is useful in treatment and in testing is as follows:

Item	NSN
Bottle, drop-dispenser, plastic, 60 ml	9L 6640-01-077-2468
Bottle, wash, laboratory, plastic (500 ml)	9L 6640-00-314-2097
Desiccant, 1 lb bags or 1/2 lb bags	9G 6850-00-264-6572 or 9G 6850-00-264-6571
Humidity indicator card, can of 125	9G 6685-00-752-8240
Jerrican, polyethylene, screw cap, 5 gallons	9L 6640-01-083-9756
Jug, polyethylene, safety dispensing, screw cap, 2 1/2 gallons	9L 6640-01-083-9755
Morpholine black glass float, BP-4	1H 6680-01-108-4275
Morpholine rotameter tube, 1/8-10-G-3	1H 4710-01-108-4267
Morpholine stainless steel float, BJ-4	9G 6680-01-038-6026
Scale, 16 lb, with counter weights	9G 6670-00-641-3485
Scale, 24 oz capacity	9G 6670-00-937-2690
Scoop, plastic, 2 inch bowl	9Q 7330-01-079-0694
Sodium nitrite, ACS grade, 5 lb	9G 6810-00-270-3254
Spatula, laboratory, nickel-plated steel	9L 6640-00-171-5198
Stopper, solid rubber, 1 lb (approx 13) size 9	9L 6640-00-935-1108

220-31.242 ALLOWANCE EQUIPAGE AND PARTS LIST

220-31.243

The following allowance equipage and parts lists apply to test and treatment of propulsion boiler water and feedwater:

1. AEL 2-560004101, Kit, Boiler Water/Feedwater Test and Treatment
2. AEL 2-560004102, Meter, Conductivity Test of Boiler Water.
3. AEL 2-560004103, Chemicals and Equipment, Boiler Water/Feedwater Test and Treatment (Quantities based on the number of boilers).

4. AEL 2-560004104, Chemicals and Equipment, Boiler Water/Feedwater Test and Treatment (Quantities based on boiler water treatment volume).
5. AEL 2-560004055, Kit, Dissolved Oxygen Test of Feedwater.
6. AEL 2-560004075, Meter, pH Test of Boiler Water and Feedwater.
7. APL 461620001, pH Meter.
8. AEL 2-560004108, Silica Test Kit.

220-31.244

AEL and APL quantity changes are updated by the ship by forwarding a change request to SPCC Mechanicsburg, PA.

220-31.245 MATERIAL CONTROL

220-31.246

Control of the material required for testing and treatment of feedwater and boiler water is necessary. An adequate supply must be maintained, stored properly, and have remaining shelf life.

220-31.247 MINIMUM ONBOARD STOCK.

Minimum onboard stock for laboratory test equipment and test and treatment chemicals required for a normal six month deployment is listed in Table 220-31-18 for COPHOS treated main propulsion boilers. Similar tables are included in Section 22, Section 29 and Section 30 for chelant, auxiliary and waste heat treated main propulsion boilers. Actual ship usage may vary. If actual shipboard usage based on historical data is greater than the quantities listed in the tables, the actual usage shall be used as the onboard requirement. A monthly inventory of test and treatment chemicals is required to ensure maintenance of sufficient onboard supplies of in date material. At the end of each month record the following information for each applicable chemical listed in the Boiler Water/Feedwater Test and Treatment Chemical Inventory Log (Figure 220-27-1, sheets 3 and 4):

a. The quantity onboard with less than six months shelf life remaining. Do not record expired material.
b. The quantity onboard with six or more months shelf life remaining.
c. The minimum onboard stock required for a six month deployment.
d. Determine if the quantities onboard are sufficient, by recording yes or no in the sufficient onboard stock column. If the quantity onboard is not sufficient, the ″no″ entry shall be circled in the log.

The completed inventory log shall be included as part of the monthly water treatment log package. Items listed on the log that are not ship applicable may be lined out.

220-31.248 MATERIAL STORAGE.

Nitric acid and mercuric nitrate stock solutions shall be stored in the original packing in chemical resistant metal chests or lockers (normally located in the test laboratory). All chemicals are to be stored in areas where the temperature does not exceed 38°C (100°F). Spare glassware should be cushioned in storage to avoid breakage. Dissolved oxygen ampoules shall be stored in their box away from direct light. The ampoules deteriorate with exposure to light.

220-31.249 SHELF LIFE.

Stock solutions, indicators, and standards are subject to deterioration during storage. For this reason various shelf lives have been imposed on these materials to minimize errors in testing boiler water and feedwater. The shelf life of a material is measured from its date of manufacture. It is recommended that shelf life control procedures be established and maintained.

Table 220-31-18 RECOMMENDED ONBOARD STOCK FOR 6-MONTH DEPLOYMENT

Item	NSN	Unit of Issue	Qty	Notes
BASIC EQUIPMENT				
Boiler water testing cabinet (complete)	1H 6630-00-372-0839	EA	1	[b]
Boiler water conductivity test equipment (complete)	All items in 220-28.6	N/A	1 set	[b]
Dissolved oxygen testing kit (complete)	9G 6635-01-044-6065	KT	1	[c]
Hardness test equipment	All items in 220-28.9	N/A	1	[b]
pH meter kit	All items in 220-28.8	N/A	1	[b]
Silica Test Kit	1H 4410-01-183-7442	KT	1	[b]
STOCK CHEMICALS				
Amino acid reagent pillows	9G 6810-01-169-1770	BT (100)	1	[b]
Ampoules, 0-40 ppb oxygen	9L 6630-01-068-5210	PG (30)	7	[c]
Chloride indicator capsules	9G 6810-00-753-4907	BT (12)	1	[a]
Citric acid reagent pillows	9G 6810-01-169-6568	BT (100)	1	[b]
Dimethylglyoxime	9G 6810-01-082-5414	BT (25 g)	1	[a]
Hardness buffer	9G 6850-01-390-4335	BT (100 g)	1	[a]
Hardness indicator	9G 6850-01-390-4339	BT (100 g)	1	[a]
Hardness titrating solution	9G 6810-01-072-1978	GL	1	[a]
Isopropyl alcohol (isopropanol, 2-propanol)	9G 6810-00-227-0410	GL	1	[a]
Mercuric nitrate	9G 6810-00-281-4163	BT (4 oz)	3	[a]
Methyl purple indicator capsules	9G 6810-00-142-9290	BT (12)	1	[a]
Nitric acid	9G 6810-00-270-9978	QT	1	[a]
Phenolphthalein indicator	9G 6810-00-223-7612	1 BT (100 g)	1	[a]
Potassium chloride crystals	9L 6810-00-136-1004	BT (4 oz)	4	[b]
Silica-1 reagent	9G 6810-01-169-1773	BT (2 oz)	1	[b]
STANDARDS				
Chloride (2.0 epm)	9G 6810-01-129-3762	BT (75 ml)	12	[b]
Conductivity (1,400 µmho/cm)	9G 6810-00-945-7682	BT (250 ml)	12	[b]
Hardness (0.2 epm)	9G 6810-01-125-5234	BT (150 ml)	8	[b]
Methyl purple alkalinity (6.0 epm)	9G 6810-01-259-8231	BX(6-100 ml btl)	4	[a]
pH 7.00 ± 0.05 at 25°C	9G 6810-01-239-7562	BX (Box of 50)	4	[b]
pH 10.00 ± 0.05 at 25°C	9G 6810-01-239-7563	BX (Box of 50)	4	[b]

Table 220-31-18 RECOMMENDED ONBOARD STOCK FOR 6-MONTH DEPLOYMENT - Continued

Item	NSN	Unit of Issue	Qty	Notes
TREATMENT CHEMICALS				
Caustic soda (lye, sodium hydroxide)	9Q 6810-00-270-8177	CO (500 g)	4	a
Desiccant, 1 lb bag	9G 6850-00-264-6572	DR (150 bags)	2	a
Desiccant, 1/2 lb bag	9G 6850-00-264-6571	DR (300 bags)	4	a
Disodium phosphate anhydrous (sodium phosphate, dibasic, O-S-639)	9G 6810-00-584-4298	DR (25 lb)	4	a
Humidity indicator card	9G 6685-00-752-8240	CN (125)	2	a
Ion exchange resin (carriers excluded)	9G 6810-01-029-4217	CF	12	d f
Ion exchange resin (carriers)	9G 6810-01-029-4217	CF	48	d f
Morpholine, 40% (carriers excluded)	9G 6810-00-419-4298	CN (5 gal)	4	a e
Morpholine, 40% (carriers)	9G 6810-00-419-4298	CN (5 gal)	30	a e
Sodium Nitrite	9G 6810-00-270-3254	BT (5 lb)	30	a
Trisodium phosphate dodecahydrate (sodium phosphate, tribasic, dodecahydrate, O-S-642, Type II)	9G 6810-01-082-5415	DR (25 lb)	16 (600) 8 (1200)	a a
SAFETY EQUIPMENT				
Apron, rubber	9Q 8415-00-634-5023	EA	1	a
Face shield	9Q 4240-00-542-2048	EA	2	a
Finger cot	9L 6515-00-935-1194	PG (144)	2	c
Gloves, chemical protective	9D 8415-00-266-8677	PR	6	a
Gloves, plastic	9D 8415-00-682-6786	PR	100	a
Goggles	9G 4240-01-364-2169	PR	2	a
SPARE EQUIPMENT				
Adaptor (to connect electrode to Model SA 720 pH meter)	1H 0099-LL-H26-4985	EA	2	b
Aspirator bulb assembly (for filling burets)	1H 6640-00-291-1162	EA	3	b
Bottle, dropper, 60 ml, glass	9L 6640-00-720-2752	EA	2	b
Bottle, dropper, 60 ml plastic	9L 6640-01-077-2468	PG (12)	1	b
Bottle, polyethylene, screw cap, 1 qt	9G 8125-00-819-6085	EA	12	a
Bottle, reagent, 1 liter (for nitric acid)	9L 6640-00-253-2495	EA	1	b
Bottle, reagent, 1 liter (for mercuric nitrate)	9L 6640-00-702-2540	EA	1	b
Bottle, 8 oz, square	9G 8125-00-543-7699	EA	2	b
Bottle, wash, plastic, 500 ml	9L 6640-00-314-2097	EA	3	b
Buret assembly, automatic zero, 10 ml, for hardness	1H 6640-01-072-1980	EA	3	b
Buret, automatic zero, 10 ml, for chloride and phosphate	9L 6640-00-264-6951	EA	3	b
Casserole, porcelain, white	9L 6640-00-412-8400	EA	2	b
Cell, conductivity, dip type, constant of 2.0	1H 6630-00-620-4540	EA	1	b

Table 220-31-18 RECOMMENDED ONBOARD STOCK FOR 6-MONTH DEPLOYMENT - Continued

Item	NSN	Unit of Issue	Qty	Notes
Comparator, 0-40 ppb oxygen	9L 6630-01-035-1864	EA	1	c
Cooler, sample, boiler water	1H 4420-00-376-1545*	EA	2	b
Cooler, sample, DFT	1H 4420-00-376-1545*	EA	1	b
Cylinder, graduated, 100 ml (glass), TD	9L 6640-00-420-0000	EA	5	b
Cylinder, graduated 100 ml (plastic), TD	9L 6640-00-889-7089	EA	5	b
Dipper, brass	9C 4410-01-077-2467	EA	4	b
Electrode, pH	9L 6630-01-063-9985	EA	2	b
Grease, ground glass joint	9G9150-00-965-2408	TU (150 g)	1	b
Jar, plastic	9L 6640-01-068-5095	EA	4	b
Jerrican, plastic, 5 gal	9L 6640-01-083-9756	EA	2	a
Jug, safety, plastic, 2 1/2 gal	9L 6640-01-083-9755	EA	1	a
Meter, conductivity Solubridge	9N 6625-00-620-4539	EA	1	b
Meter, pH	1H 6625-01-070-2446	EA	1	b
Rod, stirring, 7 in long	9L 6640-00-290-0154	EA	6	b
Sampler, glass, dissolved oxygen	9L 6640-01-045-0821	EA	4	c
Scale, 16 lb cap	9G 6670-00-641-3485	EA	1	b
Scale, 24 oz cap	9G 6670-00-937-2690	EA	1	b
Scoop, plastic	9Q 7330-01-079-0694	DZ	1	b
Snapper, dissolved oxygen	9Q 5120-01-090-5860	EA	5	c
Spatula, nickel plated steel	9L 6640-00-171-5198	EA	1	b
Stopper, rubber, size 9	9L 6640-00-935-1108	PG (15)	1	b
Thermometer, metal, dial type (0 to 100°C)	9G 6685-00-663-8093	EA	3	b
Tubing, neoprene, 3/16 in ID, dissolved oxygen	9C 4720-00-529-5015	FT	3	c

[b]Quantity needed per ship

[c]Quantity needed per DFT

[a]Quantity needed per two boilers

[d]Applies only to ships with demineralizers installed

[f]Per demineralizer

*The same cooler is used for boiler water, desuperheated steam, and DFT.

220-31.250

All stock chemicals, standards, pH buffers, and dissolved oxygen comparators have a 2-year shelf life, except as follows:

Item	Months of Shelf Life
Chloride indicator (capsules, from date of manufacture)	36
Chloride indicator (prepared solution, from date of preparation)	9
Dimethylglyoxime (DMG)	Unlimited
Dissolved oxygen ampoules (from date of receipt)	60
Isopropyl alcohol	Unlimited
Methyl purple indicator (capsules, from date of manufacture)	Unlimited
Methyl purple indicator (prepared solution, from date of preparation)	6
Phenolphthalein indicator	Unlimited
Potassium chloride (crystals and prepared solution)	Unlimited
Silica-1 reagent (from date of receipt)	12

220-31.251

All of the treatment chemicals, except mixed bed ion exchange resin, have an indefinite shelf life. Mixed bed ion exchange resin has a shelf life of 24 months. Do not use ion exchange resin that has been exposed to a temperature of 0°C (32°F) or less.

220-31.252

All stock chemicals should be visually examined when received. Cloudy solutions or deposits in the bottom of the bottle indicate deterioration. The caps of the liquid standards, by specification, must be sealed with plastic to prevent evaporation of liquid, prior to use.

220-31.253 FORMS.

The following forms are used to record water conditions in a steam propulsion plant. The auxiliary boiler forms are listed in Section 29. Forms may be obtained through normal supply channels in accordance with NAVSUP Publication 2002. Due to the limited use of NAVSEA 9255/8 (6-94), Boiler Water Chemistry Worksheet/Log, it will not be available in the Navy stock system. Local reproduction of this log from Appendix A is authorized.

1. NAVSEA 9255/4 (6-94), NSN 0116-LF-018-2200, Feedwater Chemistry Worksheet/Log.
2. NAVSEA 9255/6 (6-94), NSN 0116-LF-018-2300, Cover Sheet and Monthly Boiler Data.
3. NAVSEA 9255/9 (6-94), NSN 0116-LF-018-2600, Fuel and Water Report.
4. NAVSEA 9255/10 (6-94), NSN 0116-LF-018-8700, Reserve/Makeup Feedwater Tests Log.
5. NAVSEA 9255/16 (6-94), NSN 0116-LF-018-3100, Boiler Water/Feedwater Test and Treatment Chemical Inventory Log.

APPENDIX A.

BLANK WATER TREATMENT LOGS

Table 220-A-1 BLANK WATER TREATMENT LOGS

Log Number and Title
NAVSEA 9255/4 (6-94) (FRONT) Feedwater Chemistry Worksheet/Log
NAVSEA 9255/4 (6-94) (BACK) Feedwater Chemistry Worksheet/Log
NAVSEA 9255/6 (6-94) (FRONT) Water Treatment Log
NAVSEA 9255/6 (6-94) (BACK) Monthly Boiler Data
NAVSEA 9255/7 (6-94) (FRONT) Waste Heat Boiler Water Chemistry Worksheet/Log
NAVSEA 9255/7 (6-94) (BACK) Waste Heat Boiler Water Chemistry Worksheet/Log
NAVSEA 9255/8 (6-94) (FRONT) Boiler Water Chemistry Worksheet/Log
NAVSEA 9255/8 (6-94) (BACK) Boiler Water Chemistry Worksheet/Log
NAVSEA 9255/9 (6-94) (FRONT) Fuel and Water Report
NAVSEA 9255/9 (6-94) (BACK) Fuel and Water Report
NAVSEA 9255/10 (6-94) (FRONT) Reserve/Makeup Feedwater Tests Log
NAVSEA 9255/10 (6-94) (BACK) Reserve/Makeup Feedwater Tests Log
NAVSEA 9255/11 (6-94) (FRONT) Auxiliary Boiler Water Chemistry Worksheet/Log
NAVSEA 9255/11 (6-94) (BACK) Auxiliary Boiler Water Chemistry Worksheet/Log
NAVSEA 9255/14 (6-94) (FRONT) Chelant Treatment Feedwater Chemistry Worksheet/Log
NAVSEA 9255/14 (6-94) (BACK) Chelant Treatment Feedwater Chemistry Worksheet/Log
NAVSEA 9255/15 (6-94) (FRONT) Chelant Treatment Boiler Water Chemistry Worksheet/Log
NAVSEA 9255/15 (6-94) (BACK) Chelant Treatment Boiler Water Chemistry Worksheet/Log
NAVSEA 9255/16 (6-94) (FRONT) Boiler Water/Feedwater Test and Treatment Chemical Inventory Log
NAVSEA 9255/16 (6-94) (BACK) Boiler Water/Feedwater Test and Treatment Chemical Inventory Log
NAVSEA 9255/17 (6-94) (FRONT) Auxiliary/Waste Heat Feedwater Chemistry Worksheet/Log
NAVSEA 9255/17 (6-94) (BACK) Auxiliary/Waste Heat Feedwater Chemistry Worksheet/Log

FEEDWATER CHEMISTRY WORKSHEET/LOG

SYSTEM ______________ SHIP ______________ DATE ________ PAGE ______

CHEMICAL TESTS AND SALINITY/CONDUCTIVITY INDICATOR COMPARISON (REQUIRED DAILY) NOTE: mho/145=epm

TIME	INDICATOR LOCATION	CHLORIDE ml MERCURIC NITRATEx0.1= epm CHLORIDE		INDICATOR READING		COM-PARISON	HARDNESS ml EDTAx0.2= epm HARDNESS		OIL KING INITIAL
		ml	epm	mmho /cm	epm	SAT/ UNSAT	ml	epm	

DEAERATED FEED WATER

TIME	CODE	DISSOLVED OXYGEN LIMIT: 15 ppb	MORPHOLINE pH RANGE: 8.6-9.0	MORPHOLINE ROTAMETER SETTING	MORPHOLINE TANK LEVEL (gallons)

FEEDWATER TESTS

TIME	LOCATION	INDICATOR READING	CHLORIDE ml MERCURIC NITRATEx0.1= epm CHLORIDE		HARDNESS ml EDTAx0.2= epm HARDNESS		OIL KING INITIAL
		mmho/cm / epm	ml	epm	ml	epm	

NAVSEA 9255/4 (6-94)(FRONT) NSN 0116-LF-018-2200

Figure 220-A-1 Feedwater Chemistry Worksheet/Log

FEEDWATER CHEMISTRY WORKSHEET/LOG

PAGE ____________

TIME	REMARKS:

LEGEND/TEST CODE

DISSOLVED OXYGEN TESTING		MORPHOLINE TREATED SYSTEM	
PFB	PRIOR TO FEEDING THE BOILER	AOL	60 TO 90 MINUTES AFTER ON LINE
AOL	WITHIN 2–3 HOURS AFTER BOILER ON LINE	RTE	CARRIERS EVERY 4 HOURS OTHERS EVERY 12 HOURS
RTE	WITHIN 24 HOURS		

REQUIREMENTS/LIMITS (MAXIMUM)		CHLORIDE epm SALINITY INDICATOR	CHLORIDE epm CHEMICAL TEST	CONDUCTIVITY mmho/cm	HARDNESS epm
DISTILLATE		0.065	0.07	10.0	–
MAKEUP	DEMINERALIZED	–	–	1.0	–
	NONDEMINERALIZED	0.10	0.10	15.0	0.10
CONDENSATE, DRAINS & DFT	MORPHOLINE TREATED	0.04	0.02	6.0	0.02
	WITHOUT MORPHOLINE	0.02	0.02	3.0	0.02
DISTILLER AIR EJECTOR DRAINS		0.065	0.02	10.0	–

LCPO INIT.	LCPO DATE	MPA INIT.	MPA DATE	REVIEWED: (ENGINEER OFFICER)	DATE

NAVSEA 9255/4 (6–94)(BACK) NSN 0116-LF-018-2200

Figure 220-A-2 Feedwater Chemistry Worksheet/Log

WATER TREATMENT LOG

MACHINERY PLANT NO. ______

USS ______________________________

MONTH ______________, YEAR ________

CONSISTING OF PAGES 1 THROUGH _______

REVIEWED ______________________________
ENGINEER OFFICER DATE

EXAMINED ______________________________
COMMANDING OFFICER DATE

NOTE: THIS RECORD WILL BE RETAINED ON BOARD FOR 2 YEARS AND DISPOSED OF IN ACCORDANCE WITH SECNAVINST 5212.B.SUP-1, PARA. 9510(1). TRANSCRIPT(S) WILL BE FURNISHED TO NAVSEASYSCOM WHEN REQUIRED.

NAVSEA 9255/6 (6-94)(FRONT) NSN 0116-LF-018-2300

Figure 220-A-3 Water Treatment Log

MONTHLY BOILER DATA

BOILER NO.			
STEAMING HOUR DATA			
TOTAL LAST MONTH			
HOURS THIS MONTH			
TOTAL STEAMING HOURS			
HOURS RUN DRY			
CONTAMINATION			
STM. HRS. MODERATE			
STM. HRS. SERIOUS			
INSPECTIONS			
SGPI			
DATE LAST INSPECTED			
INSPECTED BY			
STM. HRS. SINCE INSP.			
CHENG			
WATERSIDES			
DATE LAST INSPECTED			
INSPECTED BY			
STM. HRS. SINCE INSP.			
FIRESIDES			
DATE LAST INSPECTED			
INSPECTED BY			
STM. HRS. SINCE INSP.			
CLEANINGS			
WATER JET,WIREBRUSH OR EDTA WATERSIDE CLEANING			
DATE LAST CLEANED			
TYPE OF CLEANING			
STM. HRS. SINCE CLN.			
HYDROCHLORIC/SULF AMIC ACID WATERSIDE CLEANING			
DATE LAST CLEANED			
STM. HRS. SINCE CLN.			
FIRESIDE CLEANING			
DATE LAST CLEANED			
STM. HRS. SINCE CLN.			
CHEMICAL AND BLOWDOWN DATA			
TOTAL oz/g TSP			
TOTAL oz/g DSP			
TOTAL OUNCES C.S.			
NO. OF SURFACE BLOWS			
NO. OF BOTTOM BLOWS			

BOILER SAFETY VALVES SET			
	DATE	PRESSURE	
		LIFT	RESEAT
BOILER NO.			
PILOT			
SUPERHEATER			
#1 DRUM			
#2 DRUM			
#3 DRUM			
#4 DRUM			
BOILER NO.			
PILOT			
SUPERHEATER			
#1 DRUM			
#2 DRUM			
#3 DRUM			
#4 DRUM			
BOILER NO.			
PILOT			
SUPERHEATER			
#1 DRUM			
#2 DRUM			
#3 DRUM			
#4 DRUM			

WATER CHEMISTRY STANDARDS RUN		
TEST	DATE	RESULT
CONDUCTIVITY		
CHLORIDE		
ALKALINITY		
HARDNESS		

DATES OF IMPORTANT EVOLUTIONS			
BOILER NO.			
LAST 150% HYDRO			
LAST 135% HYDRO			
LAST 125% HYDRO			
LAST TUBE NDE			
SOOT BLOWER NDE			
BOTTOM BLOWDOWN PIPING NDE			
AIR CASING TEST			
SATISFACTORY BOILER FLEXIBILITY TEST			

GOVERNOR SETTINGS									
NUMBER									
FORCED DRAFT BLOWERS	DATE / SETTING								
NUMBER									
FUEL OIL SERVICE PUMPS	DATE / SETTING								
NUMBER									
MAIN FEED PUMPS	DATE / SETTING								
NUMBER									
MAIN FEED BOOSTER PUMPS	DATE / SETTING								

NAVSEA 9255/6 (6-94)(BACK) NSN 0116-LF-018-2300

Figure 220-A-4 Monthy Boiler Data

WASTE HEAT BOILER WATER CHEMISTRY WORKSHEET/LOG

BOILER NO. ________ SHIP ________ DATE ________ PAGE ________

TIME	CODE	CONDUCTIVITY LIMIT: 500 mho/cm		ALKALINITY RANGE: 0.05–0.25 epm		PHOSPHATE RANGE: 25 – 75 ppm		CHLORIDE LIMIT: 1.0 epm		CONTINUOUS INJECTION TANK LEVEL (gallons)	INLET GAS TEMP. (°F)	OIL KING INITIAL	EOOW/ EDO INITIAL
		TEMP. (°C)	mmho/cm CONDUC–TIVITY	ml PHENOL–PHTHALEIN	ml/4 = epm ALKALINITY	ml METHYL PURPLE	mlx25 = ppm PHOSPHATE	ml MERCURIC NITRATE	mlx0.4 = epm CHLORIDE				

BATCH CHEMICAL TREATMENT

TIME	TRISODIUM PHOSPHATE (grams)	TSP CORREC–TION FOR PHOSPHATE	CURRENT PHOSPHATE LEVEL	CORRECTED PHOSPHATE	DISODIUM PHOSPHATE (grams)

TOTAL TSP INJECTED	TOTAL DSP INJECTED

CONTINUOUS CHEMICAL TREATMENT

TIME	TSP (grams)	DSP (grams)

PUMP STROKE %

BLOWDOWN

TIME	TYPE	CONDUCTIVITY		% BLOW–DOWN
		BEFORE	AFTER	

TOTAL PERCENT BLOWDOWN

NAVSEA 9255/7 (6–94)(FRONT) NSN 0116–LF–018–2400

Figure 220-A-5 Waste Heat Boiler Water Chemistry Worksheet/Log

WASTE HEAT BOILER WATER CHEMISTRY WORKSHEET/LOG

PAGE ______

TIME	REMARKS:

	STEAMING HOURS	STEAMING HOURS UNDER CONTAMINATION	
		MODERATE	SERIOUS
PRIOR HOURS STEAMED THIS MONTH			
HOURS STEAMED TODAY			
HOURS STEAMED THIS MONTH			
HOURS SINCE LAST WATERSIDE INSPECTION			
HOURS SINCE LAST GASSIDE INSPECTION			
HOURS SINCE LAST BOTTOM BLOWDOWN			
HOURS DRY OPERATION TODAY			
TOTAL HOURS DRY OPERATION			

LEGEND/TEST CODE

AOL WITHIN 30 MIN. AFTER LIGHT OFF
RTE WITHIN 8 HOURS
ADD BATCH CHEMICAL INJECTION
ACA 30 TO 60 MIN. AFTER CHEMICAL ADDITION
PTB WITHIN 60 MIN. PRIOR TO BLOWDOWN
ABD 30 TO 60 MIN. AFTER BLOWDOWN
FFT FRESHLY FILLED AND TREATED
LOF GENERATOR LIGHT OFF (STEAMING)
GEN GENERATOR LIGHT OFF (DRY)
SEC GENERATOR SECURED
D BOILER DRAINED
OTH OTHER
PTS WITHIN 90 MIN. PRIOR TO SECURING

BOILER LAYUP

DRY LAYUP
DES DESICCANT
HTD HEATED AIR

WET LAYUP
STM STEAM (SHIP)
STS STEAM (SHORE)
NIT NITROGEN
DFT HOT DFW FILL
HYD HYDRAZINE
SN SODIUM NITRITE

BLOWDOWNS
S SURFACE/SEPARATOR
B BOTTOM

LCPO INITIAL	LCPO DATE	MPA INITIAL	MPA DATE	REVIEWED: (ENGINEER OFFICER)	DATE

NAVSEA 9255/7 (6-94)(BACK) NSN 0116-LF-018-2400

Figure 220-A-6 Waste Heat Boiler Water Chemistry Worksheet/Log

BOILER WATER CHEMISTRY WORKSHEET/LOG

BOILER NO. ____________ SHIP ____________ DATE ____________ PAGE ____________

TIME	CODE	pH RANGE: TYPE A: 10.20–10.60 TYPE B: 9.80–10.20				CONDUCTIVITY LIMIT: TYPE A: 600 TYPE B: 400 mmho/cm	PHOSPHATE RANGE: TYPE A: 50–120 ppm TYPE B: 25–60 ppm				CHLORIDE LIMIT: 1.00 epm		BOILER LOAD PERCENT %	OIL KING INITIAL	EOOW/ EDO INITIAL
		TEMP (%%DC)	pH METER READING	CORREC- TION	CORRECTED pH	CONDUCTIVITY mmho/cm	ml PHEN- OLPH- THALEIN	APPROX- IMATE pH	ml METHYL PURPLE	mlx25= ppm PHOSPHATE	ml MERC. NITRATE	mlx0.4= epm CHLORIDE			

CHEMICAL TREATMENT						
TRISODIUM PHOSPHATE (ounces)	TSP CORRECTION FOR PHOSPHATE	CURRENT PHOSPHATE LEVEL	CORRECTED PHOSPHATE	DISODIUM PHOSPHATE (ounces)	CAUSTIC SODA (ounces)	TIME INJECTED

BLOWDOWN				
TIME	TYPE	CONDUCTIVITY		% SURFACE BLOW- DOWN
		BEFORE	AFTER	

pH METER STANDARDIZATION		
TIME	% SLOPE (92% MIN)	INITIAL

TOTAL TSP INJECTED	TOTAL DSP INJECTED	TOTAL CAUSTIC SODA INJECTED	TOTAL PERCENT SURFACE BLOWDOWN

NAVSEA 9255/8 (6–94)(FRONT)

Figure 220-A-7 Boiler Water Chemistry Worksheet/Log

BOILER WATER CHEMISTRY WORKSHEET/LOG

PAGE ______

TIME	REMARKS:

LEGEND/TEST CODE

PTL WITHIN 60 MIN. PRIOR TO LIGHTOFF
AOL1 WITHIN 30 MIN. AFTER ON LINE
AOL2 WITHIN 60 TO 75 MIN. AFTER AOL1
AOL3 WITHIN 60 TO 75 MIN. AFTER AOL2
RTE WITHIN 8 HOURS
ADD CHEMICAL ADDITION
ACA 60 TO 90 MIN. AFTER CHEMICAL ADDITION
PTB WITHIN 60 MIN. PRIOR TO BLOWDOWN
ABD 30 TO 45 MIN. AFTER BLOWDOWN
PTS WITHIN 90 MIN. PRIOR TO SECURING
FFT FRESHLY FILLED AND TREATED
LOF LIGHTOFF
ONL ON LINE
SEC SECURED
D DUMPED
OTH OTHER

BOILER LAYUP

DRY LAYUP
DES DESICCANT
HTD HEATED AIR

WET LAYUP
STM STEAM (SHIP)
STS STEAM (SHORE)
NIT NITROGEN
DFT HOT DFW FILL
HYD HYDRAZINE
SN SODIUM NITRITE

BLOWDOWNS
S SURFACE
B BOTTOM

	STEAMING HOURS	STEAMING HOURS UNDER CONTAMINATION	
		MODERATE	SERIOUS
PRIOR HOURS STEAMED THIS MONTH			
HOURS STEAMED TODAY			
HOURS STEAMED THIS MONTH			
HOURS SINCE LAST WATERSIDE INSPECTION			
HOURS SINCE LAST FIRESIDE INSPECTION			
HOURS SINCE LAST BOTTOM BLOWDOWN			

LCPO		MPA		REVIEWED: (ENGINEER OFFICER)	DATE
INITIAL	DATE	INITIAL	DATE		

NAVSEA 9255/8 (6–94)(BACK)

Figure 220-A-8 Boiler Water Chemistry Worksheet/Log

FUEL AND WATER REPORT

DATE______________

TO: COMMANDING OFFICER, USS

	FUEL (gallons)		LUBE OIL STORAGE TANKS (gallons)		WATER (gallons)	
	BOILER/GT FUEL	DIESEL FUEL/ JP-5	2190	9250/23699	POTABLE	RESERVE FEED
ON HAND LAST REPORT						
RECEIVED (+)						
DISTILLED (+)						
EXPENDED (–)						
GAIN (+) LOSS (–) BY INVENTORY						
ON HAND THIS REPORT						
ON HAND %						

POTABLE WATER RECORD		
PERSONNEL ON BOARD	GALLONS USED PER PERSON	STANDARD

FEEDWATER CONSUMPTION	
NOT UNDERWAY (gallons per hour)	UNDERWAY (gallons per hour)

REMARKS:

NAVSEA 9255/9 (6–94)(FRONT) NSN 0116–LF–018–2600

Figure 220-A-9 Boiler Water Chemistry Worksheet/Log

FUEL AND WATER REPORT

HOURS SINCE INSPECTION	BOILER WATER CONDITIONS RECORD THE BOILER WATER TEST RESULTS IN THE DESIGNATED SPACES. RESULTS NOT WITHIN LIMITS MUST BE CIRCLED IN RED AND EXPLAINED IN REMARKS ON THE FRONT OF THIS REPORT.

			LAST SAMPLE				RANGE OF RESULTS							
BOILER NO.	FIRE-SIDE	WATER-SIDE	pH/ ALK	COND.	PHOS-PHATE	CHLOR-IDE	pH/ALK	COND.	PHOS-PHATE	CHLOR-IDE	HOURS STEAMED UNDER CONTAM-INATION	LAYUP CODE	DAYS UNDER LAYUP	HOURS SINCE BOTTOM BLOW-DOWN
							MAX				MOD			
							MIN				SER			
							MAX				MOD			
							MIN				SER			
							MAX				MOD			
							MIN				SER			
							MAX				MOD			
							MIN				SER			
							MAX				MOD			
							MIN				SER			
							MAX				MOD			
							MIN				SER			
							MAX				MOD			
							MIN				SER			
							MAX				MOD			
							MIN				SER			
							MAX				MOD			
							MIN				SER			
							MAX				MOD			
							MIN				SER			
							MAX				MOD			
							MIN				SER			
							MAX				MOD			
							MIN				SER			

FEEDWATER CONDITIONS												
SYSTEM	DISSOLVE OXYGEN (ppb)				epm CHLORIDE				FEEDWATER pH/HYDRAZINE			
	1	2	3	4	1	2	3	4	1	2	3	4
RANGE OF RESULTS	MAX				MAX				MAX			
	MIN				MIN				MIN			

BOILER WATER LIMITS						
	TYPE A	TYPE B	CHELANT	HIDEOUT	AUX	WASTEHEAT
pH/ALK (epm)	10.2–10.6	9.8–10.2	0.10–1.00	9.2–10.3	0.10–0.50	0.05–0.25
CONDUCTIVITY (mho/cm MAX)	600	400	500	300	600	500
PHOSPHATE(ppm)	50–120	25–60	10–40	10–30	50–100	25–75
CHLORIDE (epm MAX)	1.0	1.0	1.0	1.0	1.0	1.0

FEEDWATER LIMITS		
	WITH MORPHOLINE TREATMENT	WITHOUT MORPHOLINE TREATMENT
DISSOLVED OXYGEN (ppb)	15 MAX	15 MAX
SALINITY INDICATOR (epm)	0.04 MAX	0.02 MAX
CONDUCTIVITY INDICATOR(mho/cm)	6.0 MAX	3.0 MAX
pH	8.6 – 9.0	–
HYDRAZINE	–	10–40

BOILER LAYUP	
LAYUP CODE	TIME LIMIT
%%UDRY	
DES DESICCANT	UNLIMITED
HTD HEATED AIR	UNLIMITED
%%UWET	
STM 150 psi STM. (SHIP)	30 DAYS
STS 150 psi STM. (SHORE)	30 DAYS
NIT NITROGEN	30 DAYS
DFT HOT DFW FILL	2 WEEKS
HYD HYDRAZINE	UNLIMITED
SN SODIUM NITRITE	UNLIMITED

PREPARED BY: (OIL KING)	REVIEWED: (MPA)	REVIEWED: (ENGINEER OFFICER)

NAVSEA 9255/9 (6–94)(BACK) NSN 0116–LF–018–2600

Figure 220-A-10 Fuel and Water Report

RESERVE/MAKEUP FEEDWATER TESTS LOG

(FILL IN APPLICABLE COLUMNS)

SHIP ______________________________ DATE ____________

TANK NO.	TIME	CODE	SALINITY INDICATOR, epm	CONDUCTIVITY INDICATOR, mmho/cm	CHLORIDE		HARDNESS		DEMINERALIZER CONDUCTIVITY		OIL KING INITIAL
					LIMIT: 0.10 epm MAX		LIMIT: 0.10 epm MAX		INLET MAX 15μmho/cm	OUTLET MAX 1.0mmho/cm	
			LIMIT: 0.10 epm	LIMIT: 15 μmho/cm	ml MERCURIC NITRATE	ml x 0.1= epm	ml EDTA	ml x 0.2= epm			

LEGEND/TEST CODE			
DAY DAILY	AOS AFTER ON SUCTION	PPS PRIOR TO PLACING ON SUCTION	OTH OTHER

NAVSEA 9255/10 (6-94)(FRONT) NSN 0116-LF-018-8700

Figure 220-A-11 Fuel and Water Report

RESERVE/MAKEUP FEEDWATER TESTS LOG

PAGE________

TIME	REMARKS:

INIT.	LCPO	DATE	INIT.	MPA	DATE

REVIEWED (ENGINEER OFFICER) DATE

SHORE SOURCE FEEDWATER CHEMICAL TEST DATA

CONSTITUENT OR PROPERTY	STEAM CONDENSATE		PROCESSED FEEDWATER	
	SUPPLIER	SHIP	SUPPLIER	SHIP
pH RANGE	8.0–9.5	> 5.4	NOT REQ.	5.4–8.2
HARDNESS epm LIMIT	0.10	0.10	NOT REQ.	0.10
CONDUCTIVITY mmho/cm LIMIT	25	< 40	2.5	< 40
SILICA ppm LIMIT	0.2	0.2	0.2	0.2
ACTIVITY				

NAVSEA 9255/10 (6–94)(BACK) NSN 0116–LF–018–8700

Figure 220-A-12 Reserve/Makeup Feedwater Tests Log

AUXILIARY BOILER WATER CHEMISTRY WORKSHEET/LOG

BOILER NO. ______ SHIP ______ DATE ______ PAGE ______

TIME	CODE	CONDUCTIVITY LIMIT: 600 mho/cm		ALKALINITY RANGE: 0.1 – 0.5 epm		PHOSPHATE RANGE: 50–100 epm		CHLORIDE LIMIT: 1.0 epm		OIL KING INITIAL	EOOW/ EDO INITIAL
		TEMP. (℃)	CONDUCT–IVITY mmho/cm	ml PHENOL–PHTHALEIN	ml/4 = epm ALKALINITY	ml METHYL PURPLE	mlx25 = ppm PHOSPHATE	ml MERCURIC NITRATE	mlx0.4 = epm CHLORIDE		

CHEMICAL TREATMENT					
TIME	TRISODIUM PHOSPHATE (grams)	TSP CORRECTION FOR PHOSPHATE	CURRENT PHOSPHATE LEVEL	CORRECTED PHOSPHATE	DISODIUM PHOSPHATE (grams)

BLOWDOWN				
TIME	TYPE	CONDUCTIVITY		% BLOWDOWN
		BEFORE	AFTER	

TOTAL TSP INJECTED	TOTAL DSP INJECTED	TOTAL % SURFACE BLOWDOWN

NAVSEA 9255/11 (6–94)(FRONT) NSN 0116–LF–018–2700

Figure 220-A-13 Reserve/Makeup Feedwater Tests Log

AUXILIARY BOILER WATER CHEMISTRY WORKSHEET/LOG

PAGE ______

TIME	REMARKS:

LEGEND/TEST CODE

AOL	WITHIN 30 MIN. AFTER ON LINE
RTE	WITHIN 24 HOURS
ADD	CHEMICAL ADDITION
ACA	30 TO 60 MIN. AFTER CHEMICAL ADDITION
PTB	WITHIN 60 MIN. PRIOR TO BLOWDOWN
ABD	30 TO 60 MIN. AFTER BLOWDOWN
FFT	FRESHLY FILLED AND TREATED
LOF	LIGHTOFF
ONL	ON LINE
SEC	SECURED
D	BOILER DRAINED
OTH	OTHER
PTS	WITHIN 90 MIN. PRIOR TO SECURING
PTL	PRIOR TO LIGHTOFF

BOILER LAYUP

DRY LAYUP

DES	DESICCANT
HTD	HEATED AIR

WET LAYUP

STM	STEAM (SHIP)
STS	STEAM (SHORE)
NIT	NITROGEN
DFT	HOT DFW FILL
HYD	HYDRAZINE
SN	SODIUM NITRITE

BLOWDOWNS

S	SURFACE
B	BOTTOM

	STEAMING HOURS	STEAMING HOURS UNDER CONTAMINATION	
		MODERATE	SERIOUS
PRIOR HOURS STEAMED THIS MONTH			
HOURS STEAMED TODAY			
HOURS STEAMED THIS MONTH			
HOURS SINCE LAST WATERSIDE INSPECTION			
HOURS SINCE LAST FIRESIDE INSPECTION			
HOURS SINCE LAST BOTTOM BLOWDOWN			

LCPO		MPA		REVIEWED: (ENGINEER OFFICER)	DATE
INITIAL	DATE	INITIAL	DATE		

NAVSEA 9255/11 (6–94)(BACK) NSN 0116–LF–018–2700

Figure 220-A-14 Auxiliary Boiler Water Chemistry Worksheet/Log

CHELANT TREATMENT FEEDWATER CHEMISTRY WORKSHEET/LOG

SYSTEM ____________ SHIP ____________ DATE ____________ PAGE ______

CHEMICAL TESTS AND SALINITY/CONDUCTIVITY INDICATOR COMPARISON (REQUIRED DAILY) NOTE: mmho/145=epm

TIME	INDICATOR LOCATION	CHLORIDE: ml MERCURIC NITRATEx0.1= epm CHLORIDE — ml	CHLORIDE — epm	INDICATOR READING — mmho /cm	INDICATOR READING — epm	COM-PARISON SAT/ UNSAT	HARDNESS: ml EDTAx0.2= epm HARDNESS — ml	HARDNESS — epm	OIL KING INITIAL

FEEDWATER TREATMENT

TIME	CODE	DISSOLVED OXYGEN LIMIT: 15 ppb	HYDRAZINE RANGE: 10–40 ppb	CONTINUOUS INJECTION TANK, TANK PRESSURE ____ psi — EDTA (ounces)	TSP/DSP (ounces)	HYDRAZINE (gallons)	TANK LEVEL (gallons)

FEEDWATER TESTS

TIME	LOCATION	INDICATOR READING mmho/cm / epm	CHLORIDE: ml MERCURIC NITRATEx0.1= epm CHLORIDE — ml	CHLORIDE — epm	HARDNESS: ml EDTAx0.2= epm HARDNESS — ml	HARDNESS — epm	OIL KING INITIAL

NAVSEA 9255/14 (6–94)(FRONT) NSN 0116–LF–018–2800

Figure 220-A-15 Auxiliary Boiler Water Chemistry Worksheet/Log

CHELANT TREATMENT FEEDWATER CHEMISTRY WORKSHEET/LOG

PAGE__________

TIME	REMARKS:

LEGEND/TEST CODE

DISSOLVED OXYGEN TESTING		CHELANT TREATMENT	
PFB	PRIOR TO FEEDING THE BOILER	AOL	8 TO 10 HOURS AFTER ON LINE
AOL	WITHIN 2–3 HOURS AFTER BOILER ON LINE	RTE	WITHIN 24 HOURS
RTE	WITHIN 24 HOURS	PRP	PREPARED CONTINUOUS INJECTION TANK
		CTOL	CONTINUOUS TREATMENT ON–LINE
		CTS	CONTINUOUS TREATMENT SECURED

REQUIREMENTS/LIMITS (MAXIMUM)		CHLORIDE epm		CONDUC–TIVITY mmho/cm	HARDNESS epm
		SALINITY INDICATOR	CHEMICAL TEST		
DISTILLATE		0.065	0.07	10.0	–
MAKEUP	DEMINERALIZED	–	–	1.0	–
	NONDEMINERALIZED	0.10	0.10	15.0	0.10
CONDENSATE, DRAINS, DFT		0.02	0.02	3.0	0.02
DISTILLER AIR EJECTOR DRAINS		0.065	0.02	10.0	–

LCPO		MPA		REVIEWED: (ENGINEER OFFICER)	DATE:
INITIAL	DATE	INITIAL	DATE		

NAVSEA 9255/14 (6–94)(BACK)

NSN 0116–LF–018–2800

Figure 220-A-16 Chelant Treatment Feedwater Chemistry Worksheet/Log

CHELANT TREATMENT BOILER WATER CHEMISTRY WORKSHEET/LOG

BOILER NO. ______ SHIP ______ DATE ______ PAGE ______

TIME	CODE	CONDUCTIVITY LIMIT: 500 mho/cm			ALKALINITY RANGE: 0.100 – 1.000 epm		PHOSPHATE RANGE: 10 – 40 ppm		CHLORIDE LIMIT: 1.0 epm		BOILER LOAD PERCENT %	OIL KING INITIAL	EOOW/ EDO INITIAL
		CONTINUOUS MONITOR mmho/cm	TEMP (%%DC)	mmho/cm	ml PHENOL– PHTHALEIN	ml/4 = epm	ml METHYL PURPLE	mlx25 = ppm	ml MERCURIC NITRATE	mlx0.4 = epm			

BATCH CHEMICAL TREATMENT			TIME INJECTED
TRISODIUM PHOSPHATE (ounces)	DISODIUM PHOSPHATE (ounces)	CAUSTIC SODA (ounces)	
			TOTAL OUNCES

BLOWDOWN					
TIME		TYPE	CONDUCTIVITY		% BLOWDOWN
START	FINISH		BEFORE	AFTER	
		TOTAL PERCENT SURFACE BLOWDOWN			

NAVSEA 9255/15 (6–94)(FRONT)

NSN 0116–LF–018–2900

Figure 220-A-17 Chelant Treatment Feedwater Chemistry Worksheet/Log

CHELANT TREATMENT BOILER WATER CHEMISTRY WORKSHEET/LOG

PAGE ____________

TIME	REMARKS:

LEGEND/TEST CODE

PTL WITHIN 60 MIN. PRIOR TO LIGHTOFF
AOL WITHIN 30 MIN. AFTER ON LINE
RTE WITHIN 24 HOURS
ADD BATCH CHEMICAL ADDITION
ACA 60 TO 90 MIN. AFTER CHEMICAL ADDITION
PTB WITHIN 60 MIN. PRIOR TO BLOWDOWN
ABD 30 TO 45 MIN. AFTER BLOWDOWN
PTS WITHIN 90 MIN. PRIOR TO SECURING
FFT FRESHLY FILLED AND TREATED
LOF LIGHTOFF
ONL ON LINE
SEC SECURED
D DUMPED
OTH OTHER
CBOL CONTINUOUS BLOWDOWN ON-LINE
CBS CONTINUOUS BLOWDOWN SECURED

BOILER LAYUP

DRY LAYUP
DES DESICCANT
HTD HEATED AIR

WET LAYUP
STM STEAM (SHIP)
STS STEAM (SHORE)
NIT NITROGEN
HYD HYDRAZINE

BLOWDOWNS
S SURFACE
S-1 SCUM
B BOTTOM

	STEAMING HOURS	STEAMING HOURS UNDER CONTAMINATION	
		MODERATE	SERIOUS
PRIOR HOURS STEAMED THIS MONTH			
HOURS STEAMED TODAY			
HOURS STEAMED THIS MONTH			
HOURS SINCE LAST WATERSIDE INSPECTION			
HOURS SINCE LAST FIRESIDE INSPECTION			
HOURS SINCE LAST SURFACE BLOWDOWN			
HOURS SINCE LAST BOTTOM BLOWDOWN			

LCPO		MPA		REVIEWED: (ENGINEER OFFICER)	DATE
INITIAL	DATE	INITIAL	DATE		

NAVSEA 9255/15 (6-94)(BACK) NSN 0116-LF-018-2900

Figure 220-A-18 Chelant Treatment Feedwater Chemistry Worksheet/Log

BOILER WATER/FEEDWATER TEST AND TREATMENT CHEMICAL INVENTORY LOG

SHIP __________ DATE __________ PAGE __________

ITEM	NSN	QTY WITH LESS THAN 6 MONTHS SHELF LIFE REMAINING	QTY WITH 6 MONTHS OR MORE SHELF LIFE REMAINING	QTY REQUIRED FOR 6 MONTH DEPLOYMENT	SUFFICIENT ONBOARD STOCK? YES/NO
%%USTANDARDS CHLORIDE (2.0 epm)	9G 6810-01-129-3762				
CONDUCTIVITY (1,400 mho/cm)	9G 6810-00-945-7682				
HARDNESS (0.2 epm)	9G 6810-01-125-5234				
METHYL PURPLE ALKALINITY (6.0 epm)	9G 6810-01-259-8231				
pH 7.00 %%p 0.05 at 25 C °	9G 6810-01-239-7562				
pH 10.00 %%p 0.05 at 25 C °	9G 6810-01-239-7563				
%%uTREATMENT CHEMICALS CAUSTIC SODA (LYE, SODIUM HYDROXIDE)	9G 6810-00-270-8177				
DISODIUM PHOSPHATE ANHYDROUS (SODIUM PHOSPHATE, DIBASIC, O-S-639)	9G 6810-00-584-4298				
HYDRAZINE, 7%	1H 6810-01-304-5373				
ION EXCHANGE RESIN	1H 6810-01-029-4217				
MORPHOLINE, 40%	9G 6810-00-419-4298				
NITROGEN (CHELANT TREATMENT)	9G 6830-00-656-1596				
SODIUM NITRITE	9G 6810-00-270-3254				
TRISODIUM EDTA, TRIHYDRATE	1H 6810-01-312-4076				
TRISODIUM PHOSPHATE DODECAHYDRATE (SODIUM PHOSPHATE, TRIBASIC, DODECAHYDRATE, O-S-642, TYPE II)	9G 6810-01-082-5415				

NAVSEA 9255/16 (6-94)(FRONT)   NSN 0116-LF-018-3100

Figure 220-A-19 Chelant Treatment Feedwater Chemistry Worksheet/Log

BOILER WATER/FEEDWATER TEST AND TREATMENT CHEMICAL INVENTORY LOG

SHIP ______________________ DATE ______________________ PAGE ________

ITEM	NSN	QTY WITH LESS THAN 6 MONTHS SHELF LIFE REMAINING	QTY WITH 6 MONTHS OR MORE SHELF LIFE REMAINING	QTY REQUIRED FOR 6 MONTH DEPLOYMENT	SUFFICIENT ONBOARD STOCK? YES/NO
%%USTOCK CHEMICALS AMINO ACID REAGENT PILLOWS	9G 6810–01–169–1770				
AMPOULES, 0–40 ppb OXYGEN	9L 6630–01–068–5210				
AMPOULES, HYDRAZINE	1H 6810–01–312–4075				
CHLORIDE INDICATOR CAPSULES	9G 6810–00–753–4907				
CITRIC ACID REAGENT PILLOWS	9G 6810–01–169–6568				
DIMETHYLGLYOXIME	9G 6810–01–082–5414				
HARDNESS BUFFER	9G 6850–01–390–4335				
HARDNESS INDICATOR	9G 6850–01–390–4339				
HARDNESS TITRATING SOLUTION	9G 6810–01–072–1978				
ISOPROPYL ALCOHOL (ISOPROPANOL, 2–PROPANOL)	9G 6810–00–227–0410				
MERCURIC NITRATE	9G 6810–00–281–4163				
METHYL PURPLE INDICATOR CAPSULES	9G 6810–00–142–9290				
NITRIC ACID	9G 6810–00–270–9978				
PHENOLPHTHALEIN INDICATOR	9G 6810–00–223–7612				
POTASSIUM CHLORIDE CRYSTALS	9L 6810–00–136–1004				
SILICA–1 REAGENT	9G 6810–01–169–1773				

LCPO		MPA		REVIEWED: (ENGINEER OFFICER)	DATE
INITIAL	DATE	INITIAL	DATE		

NAVSEA 9255/16 (6–94)(BACK) NSN 0116–LF–018–3100

Figure 220-A-20 Boiler Water/Feedwater test and Treatment Chemical Inventory Log

AUXILIARY/WASTE HEAT FEEDWATER CHEMISTRY WORKSHEET/LOG

SYSTEM ______________ SHIP ______________ DATE ______________ PAGE ______

CHEMICAL TESTS AND SALINITY/CONDUCTIVITY INDICATOR COMPARISON (REQUIRED DAILY) NOTE: µmho/cm/145=epm

TIME	INDICATOR LOCATION	CHLORIDE ml MERCURIC NITRATEx0.1= epm CHLORIDE		INDICATOR READING		COM-PARISON	HARDNESS ml EDTAx0.2= epm HARDNESS		OIL KING INITIAL
		ml	epm	µmho /cm	epm	SAT/ UNSAT	ml	epm	

DEAERATED FEEDWATER

TIME	DFT	CODE	DISSOLVED OXYGEN 15 ppb MAX	LEGEND/TEST CODE
				AOL 2 TO 3 HOURS AFTER GENERATOR LIGHT-OFF
				RTE WITHIN 24 HOURS
				OTH OTHER

FEEDWATER TESTS

TIME	LOCATION	INDICATOR READING µmho/cm or epm	CHLORIDE ml MERCURIC NITRATEx0.1= epm CHLORIDE		HARDNESS ml EDTAx0.2= epm HARDNESS		OIL KING INITIAL
			ml	epm	ml	epm	

NAVSEA 9255/17 (6-94)(FRONT) NSN 0116-LF-018-3100

Figure 220-A-21 Boiler Water/Feedwater test and Treatment Chemical Inventory Log

AUXILIARY/WASTE HEAT FEEDWATER CHEMISTRY WORKSHEET/LOG

PAGE ______

TIME	REMARKS:

SHORE STEAM & SHORE SOURCE FEEDWATER SUPPLIER REQUIREMENTS (MAXIMUM)	SHORE STEAM/ CONDENSATE	PROCESSED FEEDWATER
CONDUCTIVITY, µmho/cm	25	2.5
HARDNESS, epm	0.10	–
DISSOLVED SILICA, ppm	0.2	0.2
pH (RANGE)	5.0 TO 9.5	–
TOTAL SUSPENDED SOLIDS, ppm	0.10	–

REQUIREMENTS/LIMITS (MAXIMUM)	SALINITY INDICATOR epm	CONDUC-TIVITY mmho/cm	CHLORIDE epm	HARDNESS epm
DISTILLATE	0.065	10.0	0.07	–
DISTILLER AIR EJECTOR DRAINS	0.065	10.0	0.05	–
RESERVE/MAKE-UP/IDLE FEEDWATER	0.10	15.0	0.10	0.10
CONDENSATE/DRAINS/FEEDWATER	0.05	8.0	0.05	0.02
SHORE SOURCE FEEDWATER	–	<40	–	0.10

LCPO		MPA		REVIEWED: (ENGINEER OFFICER)	DATE
INITIAL	DATE	INITIAL	DATE		

NAVSEA 9255/17 (6–94)(BACK) NSN 0116–LF–018–3200

Figure 220-A-22 Auxiliary/Waste Heat Feedwater Chemistry Worksheet/Log

AUXILIARY/WASTE HEAT FEEDWATER CHEMISTRY WORKSHEET/LOG

PAGE ______

TIME	REMARKS:

SHORE STEAM & SHORE SOURCE FEEDWATER SUPPLIER REQUIREMENTS (MAXIMUM)	SHORE STEAM/ CONDENSATE	PROCESSED FEEDWATER
CONDUCTIVITY, mmho/cm	25	2.5
HARDNESS, epm	0.10	–
DISSOLVED SILICA, ppm	0.2	0.2
pH (RANGE)	5.0 TO 9.5	–
TOTAL SUSPENDED SOLIDS, ppm	0.10	–

REQUIREMENTS/LIMITS (MAXIMUM)	SALINITY INDICATOR epm	CONDUC–TIVITY mmho/cm	CHLORIDE epm	HARDNESS epm
DISTILLATE	0.065	10.0	0.07	–
DISTILLER AIR EJECTOR DRAINS	0.065	10.0	0.05	–
RESERVE/MAKE–UP/IDLE FEEDWATER	0.10	15.0	0.10	0.10
CONDENSATE/DRAINS/FEEDWATER	0.05	8.0	0.05	0.02
SHORE SOURCE FEEDWATER	–	<40	–	0.10

LCPO		MPA		REVIEWED: (ENGINEER OFFICER)	DATE
INITIAL	DATE	INITIAL	DATE		

NAVSEA 9255/17 (6–94)(BACK) NSN 0116–LF–018–3200

Figure 220-A-23 Auxiliary/Waste Heat Feedwater Chemistry Worksheet/Log

GLOSSARY

Acidic — State of a water solution which is acid. The pH (an expression for the hydrogen ion concentration) of an acid solution is less than seven. The closer to zero the value of pH, the more acidic the solution.

Alkaline — State of a water solution which is alkaline. The pH of an alkaline solution is greater than seven. The closer to a pH value of 14, the more alkaline the solution.

Alkalinity — The quality or state of a solution in which there is an excess of alkali over acid.

Anion — A negatively charged ion such as chloride (Cl^-) or phosphate ($P0_4^{3-}$).

Anion-exchange resin — A material capable of the reversible exchange of negatively charged ions.

Blowdown — The expelling of a portion of the boiler water from the boiler by using the boiler pressure.

Bottom blowdown — The expelling of a portion of the boiler water from a lower unit of the boiler. A bottom blowdown is performed on each unit individually, such as the water drum, side wall header, division wall header, and so forth.

Carryover — Boiler water carried out of the boiler with the steam.

Cation — A positively charged ion such as sodium (Na^+) or calcium (Ca^{2+}).

Cation-exchange resin — A material capable of the reversible exchange of positively charged ions.

Chloride — An indication of the seawater contamination of water aboard ship.

Concentration — Of a solution, the relative content in dissolved material. Sometimes also applied to undissolved (suspended) material in a solution.

Condensate — Steam from the boiler that has been cooled and converted back to water in the condenser or by the use of the steam.

Conductivity — The measurement of the capability of a solution to conduct an electric current. The capability is expressed in a technical unit called micromhos per centimeter, which is abbreviated µmho/cm. The capability of a water to conduct an electric current is directly proportional to the dissolved solids content of the boiler water.

Constituent — Any component of a mixture or a solution.

Contamination — An excessive concentration of seawater or shore water in distillate or any water component of the boiler cycle. It also means any foreign material in the water such as fuel oil, lube oil, or corrosion products.

Corrosion — A gradual wearing away or alteration of metal by a chemical or electrochemical process. Essentially, it is an oxidizing process such as the rusting of iron by the atmosphere.

Corrosion, acidic — The dissolving of boiler tube metal caused by the acidic (low pH) boiler water. Generally exhibited by overall wall thinning.

Corrosion, caustic — The dissolving of boiler tube metal caused by high pH of the boiler water. It generally occurs underneath waterside deposits at the lower bend of the screen tubes.

Corrosion, dissolved oxygen
: The dissolving of boiler tube metal caused by air in the boiler water. It may occur as one isolated pit with tubercle or many pits and tubercles.

Corrosion products
: Products that result from a chemical or electrochemical reaction between a metal and its environment.

Corrosion, stress
: Failure by cracking under combined action of corrosion and stress, either external (applied) or internal (residual).

Deaerating feed tank (DFT)
: A feed tank in which air is removed from the feedwater. The dissolved oxygen content of properly deaerated feedwater will be less than 15 ppb.

Deionization
: The removal of all the anions and cations (except H^+ and $0H^-$) in water by a mixed bed ion exchange resin resulting in ultrapure water. Also called demineralization.

Disodium phosphate
: A chemical, slightly alkaline, used to maintain a phosphate level in boiler water. Also called sodium phosphate, dibasic.

Dissolved oxygen
: The oxygen in air that is dissolved in water. If a glass of cold water is allowed to stand in the air, it will quickly absorb air and acquire a dissolved oxygen content of 8.2 ppm providing the temperature of the water is 77°F (25°C).

Dissolved solids
: Sea and shore water, corrosion products, treatment chemicals, and other soluble materials that are dissolved in boiler water or other waters. The dissolved solids are in solution and cannot be seen.

Distillate
: The water produced by the ship's distillers. It may be considered as highly diluted seawater since it contains about 1.7 ppm of sea salts, whereas seawater contains 36,000 ppm of sea salts.

Equivalent per million (epm)
: An expression of concentration, one equivalent unit weight of a substance dissolved in 1-million unit weights of water. It is numerically equal to its metric equivalent, milliequivalents per liter (meq/l). Each substance has been assigned a chemical equivalent; for example, the chemical equivalent of chloride is 35.5. If there were 35.5 pounds of chloride in a million pounds of solution, the chloride concentration of the water would be 1.0 epm (1.0 meq/l).

Feedwater
: Specifically, the water entering (being fed to) the boiler. It may consist, at any one time, of one of the following or any combination of them: distillate, makeup feedwater, and condensate.

Finger cot
: A protective covering for the fingertip.

Foaming
: The formation of stabilized bubbles at the water level in the steam drum caused by excessive dissolved and suspended solids. This results in a continuous, small amount of boiler water carrying over with the steam.

Grain per gallon
: An outdated U.S. Customary unit of concentration equal to 0.002285 ounce of a material dissolved per 1 gallon of water.

Hydrazine — A slightly alkaline liquid chemical that is a strong reducing agent. A catalyzed form is used as a feedwater dissolved oxygen scavenger. The stock solution is nominally 15 percent hydrazine (24 percent hydrazine hydrate).

Ion — An atom or group of atoms that carries an electric charge. Salt, sodium chloride, when dissolved in water, dissociates into two types of ions. Sodium (Na^+) is one of the types of positively charged ions called cations, while chloride (Cl^-) is a negatively charged anion type of ion. Other ions of interest are magnesium (Mg^{2+}), sulfate ($S0_4{}^{2-}$), calcium (Ca^{2+}), hydrogen (H^+), hydroxide (OH^-), phosphate ($P0_4{}^{3-}$) and iron (Fe^{2+} or Fe^{3+}). Some of the foregoing ions combine to form the following compounds: water (H_2O), calcium sulfate ($CaSO_4$), magnesium hydroxide [$Mg(OH)_2$], and calcium phosphate [$Ca_3(PO_4)_2$].

Ion exchange resin — A mixed resin bed is a mixture of two compounds. One compound substitutes the hydrogen ion for all the cations in a water. The other compound substitutes the hydroxide ion for all the anions in the water. All of the cations and anions are removed from the water. Supplied as small resin beads for ships' demineralizers.

Kilopascal (kPa) — The metric unit used to express system operating pressure. One pound per square inch of pressure is equal to 6.895 kilopascals.

Liter — A liquid volume measurement consisting of 0.001 cube meter. One U.S. gallon is equivalent to 3.785 liters.

Makeup feedwater — Reserve feedwater that is supplied to the steam system to replace water losses. Where mixed bed demineralizers are installed the effluent from the demineralizer is termed makeup feedwater.

Microgram per liter (mg/l) — A metric unit expressing concentration. It is numerically equal to parts per billion (ppb).

Micromho per centimeter (µmho/cm) — The unit for reporting the specific conductance of a solution. The dissolved ionic solids in solution are related to the conductivity. The metric unit is microsiemen per centimeter (µS/cm) and is numerically equal.

Microsiemen per centimeter (µS/cm) — The metric unit for specific conductance of solutions numerically equal to micromho per centimeter.

Milli — A prefix meaning 1-thousandth. For example, 1 milliequivalent equals 0.001 equivalent, and 1 milligram equals 0.001 gram.

Milliequivalent per liter (meq/l) — A metric unit expressing concentration. It is numerically equal to equivalent per million.

Milligrams per liter (mg/l) — A metric unit expressing solution concentration. It is numerically equal to part per million.

Milliliter (ml) — A liquid volume measurement consisting of 0.001 liter. It is a unit of volume measurement performed with a buret or a graduated cylinder.

Morpholine — An alkaline, easily volatilized chemical used to maintain the pH of the condensate/feedwater system in the alkaline range in order to reduce preboiler system corrosion.

Normality — A chemical concentration term. A one normal (1.0N) nitric acid solution would have one equivalent weight (63 grams) of nitric acid diluted to 1 liter volume with distilled water.

Part per billion (ppb)
An expression of concentration. A unit weight of substance dissolved in a 1-billion unit weight of water. If 1 pound of salt is dissolved in 1 billion pounds of water, the water will then contain 1 ppb of salt. The metric unit is microgram per liter (mg/l) and is numerically equal.

Part per million (ppm)
An expression of concentration. A unit weight of substance dissolved in a 1-million unit weight of water. If 1 pound of salt is dissolved in 1 million pounds of water, the water will then contain 1 ppm of salt. The metric unit is milligram per liter (µg/l) and is numerically equal.

Phosphate A chemical that aids in making suspended solids of the scale-forming constituents of water, therefore helping to prevent boiler waterside scale formation.

pH The negative logarithm of the effective hydrogen ion concentration or activity in gram equivalents per liter. The pH is measured in various ways. It is used for expressing acidity or alkalinity. The pH values are generally expressed on a scale of zero to 14. A pH of seven indicates the solution is neutral. A pH below seven indicates the solution is acidic. A pH greater than seven indicates the solution is alkaline.

Potable water Water of purity acceptable for drinking. This water is intended for use for hotel purposes only, never as feedwater.

Priming Slugs of boiler water, large or small, associated with the steam coming from the steam drum. Priming is a mechanical problem and is caused by rough weather and a sudden increase in steam consumption.

Rainmaker A jury-rigged sampling apparatus consisting of a copper coil submerged in a bucket of water and used to condense steam from a pier riser. Rainmaker does not refer to shore feedwater processed through a demineralizer.

Reserve feedwater
Distillate stored in reserve feed tanks. If demineralizers are installed, the influent to the demineralizer is termed the reserve feedwater.

Scale A hard adhering deposit which forms in place directly on the waterside. Scale is generally caused by excessive sea salt or shore water contamination.

Shore source feedwater
Distillate, steam condensate, or demineralized water from a shore source. It is to be used only when it has met specifications.

Shore water Water from a shore source, such as tap water.

Sludge The sediment in the lower portions o the secured boiler resulting from the settling of the boiler water suspended solids. The sediment may include, besides the suspended solids, oil and other contaminants.

Surface blowdown
The expelling of a portion of the boiler water from the steam drum.

Suspended solids
Finely divided or large visible particles suspended (not dissolved) in the boiler water or other waters. In boiler water, they consist of metal oxides and reaction products. The reaction products are caused by the treat ment chemicals in the boiler water reacting with the scale formers and corrosion products in the feedwater.

Treatment Chemical addition to boiler water or blowdown of the boiler. Maintenance of the pH of feedwater and removal of dissolved oxygen from feedwater.

REAR SECTION

NOTE

TECHNICAL MANUAL DEFICIENCY/EVALUATION EVALUATION REPORT (TMDER) Forms can be found at the bottom of the CD list of books. Click on the TMDER form to display the form.